REALIZING RESOURCE POTENTIAL

2004 ANNUAL REPORT

COMPTON PETROLEUM CORPORATION

Table of Contents

Corporate Profile

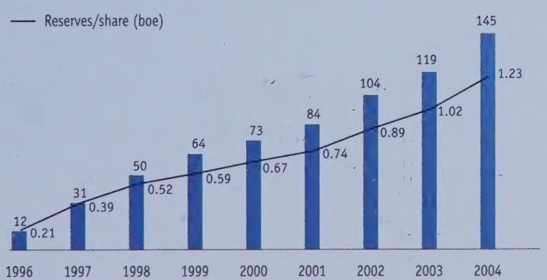
Compton Petroleum Corporation is a Calgary public, independent company actively engaged in the exploration, development and production of natural gas, natural gas liquids and crude oil in the Western Canada Sedimentary Basin. The Company's capital stock trades on the Toronto Stock Exchange (TSX) under the symbol CMT, and is included in both the S&P/TSX Composite Index and the TSX Mid-Cap Index.

Annual Meeting Information

The Annual General Meeting of Shareholders will be held on Tuesday, May 10, 2005 at 3:30 p.m. at the Chamber of Commerce, 517 – Centre Street South, Calgary, Alberta, Canada.

Compton experienced 81% growth in its share price in 2004, closing at $10.85 on December 31. Compton's stock price benefited from encouraging developments in its five resource plays, successful drilling results and the significant resource potential found within the Company's large land base.

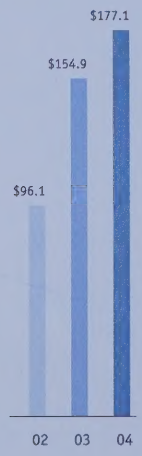
Reserve Growth
Proved + Probable (mmboe) (6:1)



* 1996-2002 Established reserves (proved + risked probable)

Share Price Performance
as at December 31 ($/share)

Cash Flow from Operations
($mm)



Financial

(000s, EXCEPT WHERE NOTED)	2004	2003	2002
TOTAL REVENUE [1]	**$ 391,659**	$ 346,565	$ 226,597
CASH FLOW FROM OPERATIONS	**$ 177,131**	$ 154,893	$ 96,072
PER SHARE – BASIC *($)*	**$ 1.51**	$ 1.33	$ 0.85
– DILUTED *($)*	**$ 1.43**	$ 1.27	$ 0.81
NET EARNINGS	**$ 63,633**	$ 118,880	$ 18,312
PER SHARE – BASIC *($)*	**$ 0.54**	$ 1.02	$ 0.16
– DILUTED *($)*	**$ 0.51**	$ 0.97	$ 0.16
CAPITAL EXPENDITURES	**$ 316,401**	$ 285,483	$ 155,108
CORPORATE DEBT, NET	**$ 417,212**	$ 355,903	$ 268,495
SHAREHOLDERS' EQUITY	**$ 424,078**	$ 356,906	$ 240,118
SHARE PRICE *($)*			
HIGH	**$ 11.43**	$ 6.35	$ 5.35
LOW	**$ 5.89**	$ 4.40	$ 3.20
CLOSE	**$ 10.85**	$ 6.00	$ 5.09
AVERAGE DAILY VOLUME OF SHARES TRADED	**674,764**	686,100	324,865

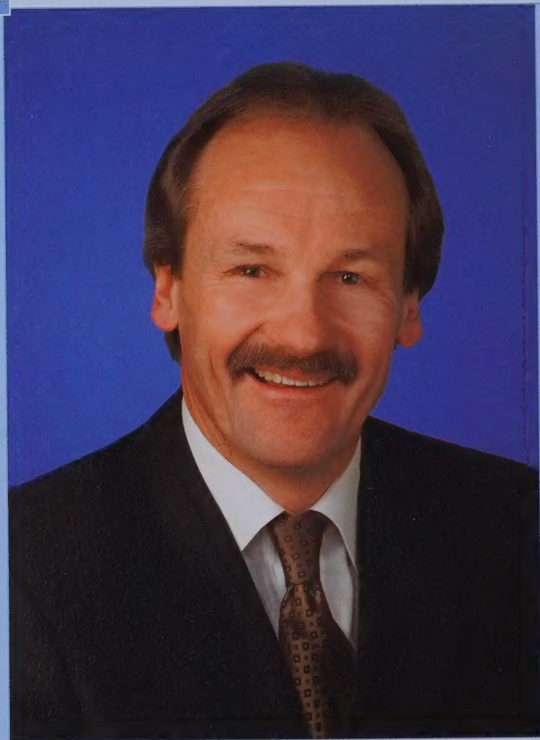
(1) Restated to exclude realized hedge gains and losses and transportation charges.

Operating

(UNITS AS NOTED)	2004	2003	2002
AVERAGE DAILY PRODUCTION VOLUMES			
NATURAL GAS (mmcf/d)	123	118	112
LIQUIDS (LIGHT OIL & NGLS) (bbls/d)	6,330	5,924	6,503
TOTAL OIL EQUIVALENT (boe/d)	26,876	25,552	25,137
AVERAGE PRICING [1]			
NATURAL GAS (per mcf)	$ 6.46	$ 6.27	$ 3.80
LIQUIDS ($/bbl)	$ 43.21	$ 35.59	$ 30.06
TOTAL OIL EQUIVALENT ($/boe)	$ 39.82	$ 37.16	$ 24.70
FIELD OPERATING NETBACK ($/boe)	$ 23.79	$ 22.05	$ 13.67
CASH FLOW NETBACK ($/boe)	$ 18.53	$ 17.11	$ 9.91
UNDEVELOPED LAND			
GROSS ACRES	1,019,854	1,042,802	1,042,923
NET ACRES	729,429	767,364	742,465
AVERAGE WORKING INTEREST	72%	74%	71%
RESERVES			
PROVED (mboe)	96,805	84,627	82,156
PROVED + PROBABLE [2] (mboe)	144,777	118,763	103,501
RESERVE LIFE INDEX (P+P) (years)	15	13	11

(1) *Restated to exclude realized hedge gains and losses and transportation charges.*

(2) *Represents proved plus risked probable reserves (established) in 2002.*



Ernie G. Sapieha,
President & Chief Executive Officer

Compton Petroleum is in an enviable position entering 2005 – we are a natural gas Company that is opportunity rich with significant upside potential. During the past few years, we have worked diligently to build a large land base, infrastructure and technical expertise in the development of unconventional tight gas reserves. This hard work has culminated in the internal generation of significant resource opportunities.

These resource opportunities comprise five major resource plays that have been identified and delineated on Compton lands. Compton, consistent with others in the industry, uses the term resource play to refer to an accumulation of natural gas which is known to exist over a large aerial expanse or thick vertical section of land or both.

Resource plays and the opportunities they provide include benefits of large reserves, multiple low risk drill locations resulting in lower costs and decreased exploration risk. Compton has identified, on its existing land base, five resource plays resulting in years of low risk, future drilling opportunities. We believe that during the next few years we will realize on these opportunities and develop this significant resource potential.

Compton is one of the few Canadian exploration companies that has acquired an expertise in unconventional gas and is successfully developing several resource plays.

Compton's resource plays consist primarily of unconventional tight gas. Wells drilled on these resource plays are expected to produce for periods in excess of 30 years compared to conventional wells, which generally produce for less than 10 years before becoming uneconomic. A tight gas well has a much steeper initial decline rate than a conventional well. However, by the third to fourth year of production, the decline rate of such a well usually decreases to less than 10% a year, compared to 25% or more for a conventional well.

Resource plays are characterized by large gas resources in place over a large area. They are often more technically complex than conventional plays. Once the technical model is mastered, the development of the resources becomes a disciplined repeatable operation with a large number of wells being drilled. The long life, low decline, reserves become a tremendous base for stable cash flow and create significant shareholder value.

Given high initial decline rates, stable production from resource plays is built up over a period of years. Each additional year of drilling layers on new production, building an overall strong production base. Compton has now reached a stage where many of our wells are past the point of high initial declines. The Company's annual average production will increase more significantly in the years to come while the overall corporate decline rate will continue to decrease.

Despite the financial success of the industry over the past few years, there has been a lack of traditional exploration occurring in Western Canada. There is now a significant move by the industry to unconventional prospects and resource plays. The key factors in pursuing such a target is technical expertise, a large land base, a repeatable technical model

(combining geology, geophysics and engineering), operatorship, control of low pressure and high pressure gathering and processing facilities. Additionally, the organization and capital necessary to drill large numbers of wells in an efficient manner is critical. Full cycle exploration required for the development of a resource play is not a short-term venture.

Compton is one of the few emerging Canadian mid-cap exploration companies that has developed the expertise and organization necessary for the development of unconventional resource plays.

We are excited at Compton's potential. We feel we have all the key elements in place. Compton will continue to focus on transferring its huge unbooked resource potential to proved and producing reserves.

The method of evaluating companies with large, unbooked reserves is changing. Value should also correlate with the accumulation of large quantities of land that contain resource plays with vast reserve potential.

How Do You Evaluate Potential?

With the maturing of traditional basins, conventional oil and gas production is continuing to decline. Higher commodity prices are encouraging producers to look beyond conventional plays. The focus on unconventional gas sources such as technically complex tight gas, coalbed methane or shale gas to maintain production is the new reality. Upstream companies focused solely on the production of conventional resources are struggling to find new opportunities.

We believe the current natural gas environment where supply and demand are in balance resulting from limited supply growth will benefit those companies with a sustainable, longer term growth profile in both production and reserves.

Key to recognizing a Company's potential and ability to prosper in such an environment is an understanding of those elements necessary for sustainable growth.

Compton's Profile

- Canadian mid-cap producer – 80% natural gas;
- All prospects are internally generated;
- 90% of 2005 reserve adds generated from the drill bit;
- Expertise in unconventional gas;
- Opportunity rich – large undeveloped land base, approximately 1,800 sections, concentrated in 3 core areas;
- Operatorship of properties and facilities;
- Reserve base of 145 million boe (1.23 boe per outstanding share) with a DCF value of $1.5 billion dollars;
- 2005 budgeted capital expenditure program of approximately $400 million dollars drilling 400 wells;
- 2005 budgeted cash flow of $240 million dollars ($180 million – 2004);
- Production base of approximately 30,000 boes per day – 80% natural gas.

Compton's profile is that of a strong Company with a solid and very valuable asset base. All the elements are in place.

Compton presently has over 1.1 million acres of land, which would be very difficult to compile today with current land prices and competition. Prices in Compton's core areas have increased several times over the past few years confirming the value of our multiple resource plays. Compton's true value is in our large, unbooked reserves found across our extensive land base in our resource plays. These five resource plays are briefly outlined below:

Resource Plays – Coalbed Methane (CBM) & Plains Belly River

These two resource plays encompass 1,000 sections of Compton's lands with CBM sitting directly on top of the Plains Belly River sands. The plays will require between 4 and 8 wells per section at a cost of $400,000 to $500,000 per well. Compton now has approximately 220 wellbores, drilled over the last four years, into the deeper Plains Belly River sands. We are now very confident in our Plains Belly River model and have budgeted 186 wells in 2005. Additionally, Compton has recently completed a resource study of the uphole CBM and recompleted six wells for CBM. The CBM results are very similar to those of successful industry competitors in the area.

Six CBM pilot programs are underway in 2005 with full geological and production results expected in November 2005. Although it is still early to estimate the full CBM potential of our lands, we are very encouraged with our results to date.

Compton is pursuing five resource plays in our core areas, with significant unbooked resource potential.

Resource Play – Callum

We drilled our first wells in late 2003 into this very technically complex, over pressured, thrusted and tight Belly River sandstone. Compton, to date, has drilled only 8 wells into this 110 section play. Compton estimates gas in place from the large columns of sands is 80+ bcf per section with potential ultimate recoveries dependent upon well density and geological rock and completion work. The Company will concentrate on detailed technical work to develop the final model for this unique play to Canada where presently the only analogs are in the Greater Green River Basin, Wyoming, U.S. The average cost of a well is approximately $2.5 million dollars and it is estimated that 8 wells per section will be required.

Resource Plays – Hooker and Niton

Compton is very pleased with its progress at Hooker and at Niton in Southern and Central Alberta respectively. In 2004, 27 gross wells were drilled at Hooker, extending the pool boundary five miles to the north and 1.5 miles to the southeast. Current production now extends over four townships, with the outer boundaries continuing to grow. Sixteen wells were drilled and cased in the Niton area, again extending the pool boundaries.

Both plays are stratigraphically the same and contain 12 to 20 bcf of gas in place per section requiring approximately 3 wells per section at an approximate cost of $1.5 million per well to drain 65% to 75% of the reserves. Hooker and Niton combined spread over 375 sections of Compton land. Both plays are estimated by Compton to contain in excess of 2 tcf of gas in place.

2004 Accomplishments

Compton had a solid year of drilling, production and reserve growth in 2004. With the expansion of the Mazeppa gas plant to 135 mmcf/d in June, Compton's processing capacity in Southern Alberta is free of restrictions with 200 mcf/d of total capacity. We exited 2004 with production of 29,400 boe/d and drilled a record 186 wells with a 90% success rate. Total proved plus probable reserves increased 22% from the prior year to 145 mboe, replacing production by 264%.

Compton had a solid year of drilling, production and reserve growth in 2004. We are positioned to capitalize on the unbooked potential of our resource plays.

Compton's 2004 activities have positioned the Company to capitalize on our resource potential. Our accomplishments in 2004 also include:

- Expansion of the Niton gas plant to 20 mmcf/d and adding a 10 mmcf/d compressor station,
- Installation of compression and a six inch pipeline from Brant to the Shouldice Gas Plant, effectively opening up a further township of Belly River drilling opportunities,
- Debottlenecking and expanding of pipelines at Hooker for additional Basal Quartz and Belly River gas production,
- Evaluating and quantifying the potential of our five resource plays,
- Completion of the Coal Bed Methane resource study and initiation of pilot projects,
- Developing a 2005 drilling program of approximately 400 wells to accelerate the recognition of our unbooked resource potential,
- Increasing our technical staff in anticipation of accelerating activities;

2005 Unlocking Compton's Potential

Compton's large land base holds enormous unconventional resource potential and we are working diligently to ensure this potential is fully reflected in our reserves and in our share price.

In the current high commodity price environment, Compton's drilling programs have the potential to add considerable value for shareholders. Based upon our experience and knowledge, we are significantly accelerating the drilling program in 2005 to increase production and demonstrate strong superior reserve growth. We will concentrate the majority of our efforts in developing our resource plays.

Compton, in 2005, is budgeting to drill approximately 400 wells and spend almost $400 million dollars. Drilling and completions will account for approximately 60% of the expenditures with 25% directed to towards facilities and the balance to land and seismic.

The funding for our programs will come from budgeted 2005 cash flow of $240 million dollars, a recently completed $90 million dollar equity issue and the balance from debt and minor property sales.

The 2005 capital program is aggressive and achievable.

While Compton and the industry are very busy, we will maintain our very high standards.

Compton, its staff, management and directors are committed to responsible resource development, safe operations, sound environmental standards and practices. Stewardship and its set of principles are an important and integral aspect of Compton's operations and are actively promoted and applied within our Company. Compton does not and will not comprise our high standards or commitment to stewardship principles in our business operations. We are continuously improving and are very proud of our performance.

Compton possesses all the key elements, including top quality people, to successfully develop its large resource potential.

Conclusion

Compton is a company in a unique position. We have generated five resource plays in our core areas with significant unbooked resource potential. We have strategically assembled over 1.1 million acres of land on trend.

We feel strongly that Compton possesses all the key factors, including top quality people, to successfully develop its large resource potential.

Compton's talented and dedicated team of people has and will continue to create value for shareholders. This value has been achieved by teamwork committed "to doing the right thing" while operating our business. The dedication, commitment and enthusiasm displayed by our people is what makes Compton a great place to work. On behalf of our shareholders, the Board of Directors and myself, I would like to express our sincere gratitude and thanks for their efforts.

I would also like to thank our outstanding Board of Directors for another year of top quality stewardship, governance and guidance.

We look forward to 2005.

Sincerely,

Ernie Sapieha

PRESIDENT & CHIEF EXECUTIVE OFFICER


WILLIAM COVER, *Manager, Drilling & Completions*


KIM DAVIES, *VP New Ventures*


ROBERT DION, *Manager, Finance*


GARY FOLLENSBEE, *Manager, Mazeppa Operations*


GEORGE FUKUSHIMA, *Manager, Reserves*


RON GERLITZ, *Manager, Acquisitions & Divestments*


MARC JUNGHANS, *VP Exploration*


CORINNA KING, *Manager, Investor Relations*


NORM KNECHT, *VP Finance & CFO*


THERESA KOSEK, *Manager, Accounting*


BILL LEONARD, *Manager Human Resources*


DEREK LONGFIELD, *VP Special Projects*


GARRY MCCULLOUGH, *Manager, Mineral Land*


TIM MILLAR, *VP, General Counsel & Corporate Secretary*


WADE MROCHUK, *Manager, Production*


PAUL PARZEN, *Manager, IT, Risk & Internal Audit*


MURRAY STODALKA, VP Engineering & Operations

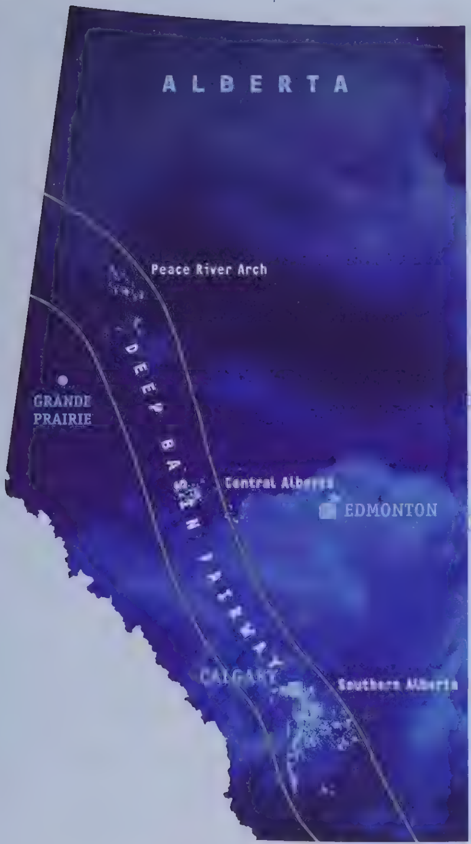

ERNIE SAPIEHA, *President & CEO*

COMPTON'S TALENTED, DEDICATED TEAM OF PEOPLE WILL CONTINUE TO CREATE SIGNIFICANT VALUE FOR SHAREHOLDERS.

RON PAN [illegible] - 2004

RON, WE WILL ALWAYS REMEMBER YOUR POSITIVE OUTLOOK AND ENTHUSIASM FOR LIFE. RON'S WONDERFUL SENSE OF HUMOUR, FRIENDLINESS AND RESPECT FOR PEOPLE CONTINUES TO INSPIRE US.

Compton engages in oil and natural gas exploration and development in the Western Canadian Sedimentary Basin of Alberta, Canada. We have focused our activities in three core areas with multi-zone potential. Core areas range from unconventional resource prospects in Southern and Central Alberta in the Deep Basin Area, to conventional gas and oil prospects in the Peace River Arch region of northwestern Alberta.

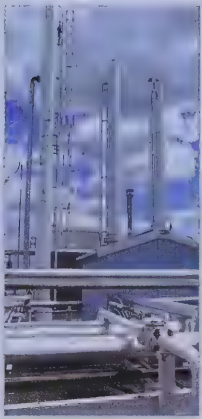


General Overview

The most prolific plays we have discovered on our lands are unconventional in nature. These systems are classified as unconventional because the reserves produce little or no water, are abnormally high or low pressured and generally found in thick columns of gas charged sedimentary section, all resulting in long life reserves.

Compton believes the unconventional gas systems we have identified cover large tracts of land. Consequently, a cornerstone of Compton's strategy is the accumulation of lands, concentrated in our core areas where we believe these reserves are present. Compton's large, contiguous land base of 1.1 million net acres (1,754 net sections) allows for successful, repeatable drilling and production from extensive reserve trends, resulting in a "resource play."

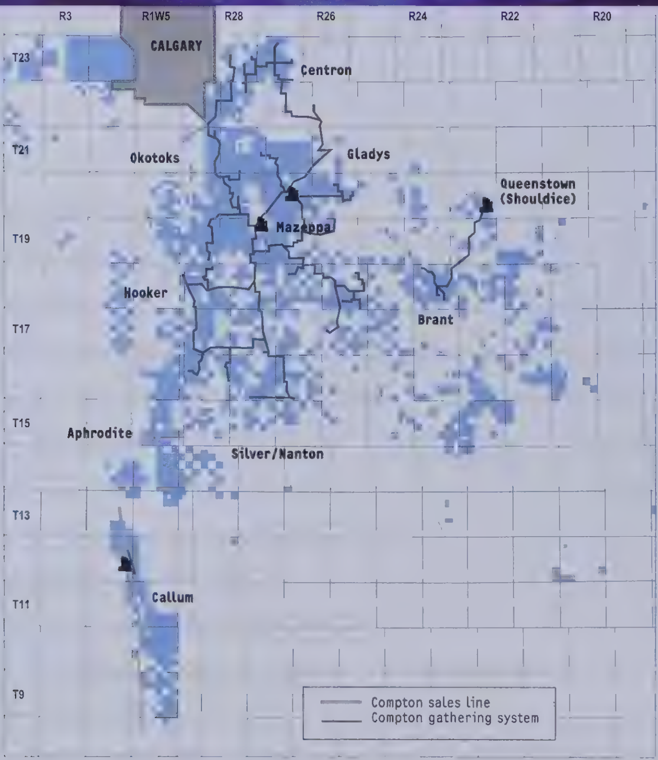
Compton established the Deep Basin extension in Southern Alberta with our Hooker discovery in 1999.



Compton continues to be one of the leaders in the pursuit of resource plays. Compton established the Deep Basin extension in Southern Alberta with our Hooker discovery in 1999 and continues to lead the way with our drilling programs at Callum and Niton. Compton has a key position in five separate resource plays including Coalbed Methane in the Horseshoe Canyon (Edmonton Formation), plains Belly River, thrusted foothills Belly River, Hooker Basal Quartz sands in Southern Alberta and the Gething/Rock Creek sands at Niton in Central Alberta.

The repeatability found within a resource play offers the potential for large reserves, predictable production levels and costs with decreased exploration risk. Compton currently has enough well locations identified across our resource plays for years of drilling. Any one of our resources plays has the potential to double the Company's natural gas reserves as at January 1, 2005.

To complement the pursuit of our five gas resource plays, Compton has amassed a broad land spread over the Peace River Arch area, which is prospective for conventional oil and gas. Compton has successfully drilled for Charlie Lake oil and Halfway oil and gas in the Arch.



Southern Alberta

Southern Alberta continues to be the focus of Compton's activities. The Company has approximately 1,220 (998 net) sections of land. The area is prospective for multiple zones, including the plains Belly River, foothills type, multiple thrusted Belly River at Callum, Basal Quartz at Hooker and the Wabamun/Crossfield. Additional upside exists in the shallower Edmonton Formation/Horseshoe Canyon Coals. In 2004, Compton drilled 101 gross (88 net) wells in Southern Alberta with a 94% success rate. The Company plans to spend $251 million in Southern Alberta in 2005 and drill 269 wells.

Horseshoe Canyon Coal Bed Methane

Compton holds approximately 960 net sections of land in Southern Alberta within the dry Horseshoe Canyon Coal Bed Methane ("CBM") fairway. Following an internal geological assessment of the CBM potential in Compton's lands, we are proceeding to quantify our CBM resource base.

During the third quarter of 2004, the Company re-completed six existing Belly River wells targeting the uphole Horseshoe Canyon Coals, primarily at Centron, Gladys and Brant. Results were similar to competitor's CBM wells immediately north of our acreage. Preliminary internal resource evaluations of the Edmonton/Horseshoe Canyon Coals estimate gas-in-place is eight to nine bcf per section. Six to eight wells will be required to fully develop the reserves, assuming a recovery rate of 50-60%.

Compton is in a unique position regarding future Edmonton/Horseshoe Canyon development. We have previously drilled 250 Belly River wells across our Southern Alberta core area, primarily on single section spacing. These existing wells were drilled through the Edmonton formation targeting the Belly River zone. Behind pipe are unperforated coals and Edmonton sands of similar quality and quantity to successful competitor CBM plays on lands that lie immediately to the north and south of Compton's landholdings. With the 2005 budget planning an additional 186 Belly River wells, Compton will have over 400 wellbores available for uphole CBM recompletions by year end 2005. The cost to drill, complete, equip and tie-in a well targeting solely Edmonton/CBM is $400,000, whereas the cost to workover an existing Belly River well for CBM is only $150,000-$200,000.

Compton currently has an extensive network of low pressure pipelines and strategically placed compressors throughout Southern Alberta to produce our Belly River gas wells. As a result little infrastructure will be required to initiate Edmonton/CBM production.

Compton has insignificant CBM reserves booked as at December 31, 2004, despite having five wells on continuous production since year end. Quantifying the reserve and delivery potential of the Edmonton/CBM over Compton's large land spread is a key objective in 2005. Compton has six CBM pilot projects underway, with results expected by the middle of the fourth quarter of 2005. The pilots will not delay Compton's plan to continue uphole recompletions of existing Belly River wells.

Plains Belly River at Centron, Gladys and Brant

The plains Belly River consists of five to six multi-stacked sands, which occur extensively over 960 net sections of Compton's Southern Alberta core area. The Company has an average working interest of 90% in this play. Wells produce approximately 150-200 mcf/d and cost $500,000 to drill, complete, equip and tie-in. Based on internal work, the Company estimates gas-in-place could be in the range of six to eleven bcf and recoveries may average 0.6+ bcf per well. Ultimate recoveries will depend on well density. Compton believes that four to six wells per section will optimize recovery of the Belly River gas.

In 2004, Compton drilled 60 gross (54 net) wells across the Centron, Gladys and Brant areas with all wells encountering multiple pay sections. To date, we have drilled 250 wells targeting the Belly River sands. The pipeline and compression system that Compton owns and operates in Southern Alberta is extensive.

Historically the majority of Compton's drilling has been on one section spacing. During the second half of 2004, Compton received approval to proceed with two wells per section on seven townships of land. This effectively doubles our current plains Belly River drilling inventory. The Company plans to drill 183 Belly River wells in 2005.

Callum Thrusted Belly River

Applying expertise developed in our plains Belly River exploration, Compton is targeting thrusted, stacked multiple Belly River tight sandstones at Callum. The Company has a 60% working interest in 110 sections of land on trend. Based upon limited initial drilling results, we estimate potential gas in place to be 80 bcf per section, with ultimate recoveries depending upon well density. Compton has an average working interest of 60% in the play.

Drilling in the Callum area is completed from pads with an eight well capability. Each new well costs approximately $2.5 million to drill, complete, equip and tie-in, with six to eight wells required per section to develop this play. Seven wells to date have been drilled in the feature, with recent completions averaging approximately 1 mmcf/d per well.

In 2004, three directional wells were drilled from a pad constructed immediately south of the Callum gas plant, plus two additional wells north of the plant. Results were encouraging, however, it is apparent that completion design is the key to unlocking this technically challenging play. Callum has the potential to become a very significant resource play for Compton and time spent assessing completion techniques is critical to the future development of this play.

Quarter section spacing over nine sections was approved by the EUB in the third quarter of 2004. Site assessment for the next drilling pad was completed in the fourth quarter of 2004, with drilling expected to commence early in 2005. Compton plans to drill 21 wells at Callum in 2005.

Hooker Basal Quartz

The Hooker trend targets tight Lower Cretaceous Basal Quartz sandstones. This play covers an extensive area of approximately 244 net sections, with Compton's working interest averaging 75%. Current production extends over four townships, with the outer boundaries of the play continuing to be expanded. The majority of the 110 gross (89 net) gas wells drilled to date at Hooker were on single section spacing, however, two wells per section spacing across 26 sections was approved by the EUB in the third quarter of 2004. Further downspacing is being applied for. Compton feels the pool can ultimately be drilled on three wells per section spacing.

Wells cost an average of $1.5 million to drill, complete, equip and tie in, while production averages 1 mmcf/d. Mapping by the Company suggests this play has the potential to grow to nine townships with reserves in place of up to 15-20 bcf per section. The same work suggests the Hooker trend has the potential to contain up to 1.5 tcf of gas-in-place potential, net to the Company. With recoveries of 65%, Hooker's resource potential is in excess of 500 bcf of net gas reserves.

In 2004, 25 gross (22 net) gas wells were drilled, extending the pool boundary five miles to the north and 1.5 miles to the southeast. The Company received downspacing approval on the southeast Hooker extension and is currently proceeding with an additional application for downspacing at the northern end of Hooker. In 2005, we plan to drill 35 wells at Hooker.

Southern Alberta Facilities

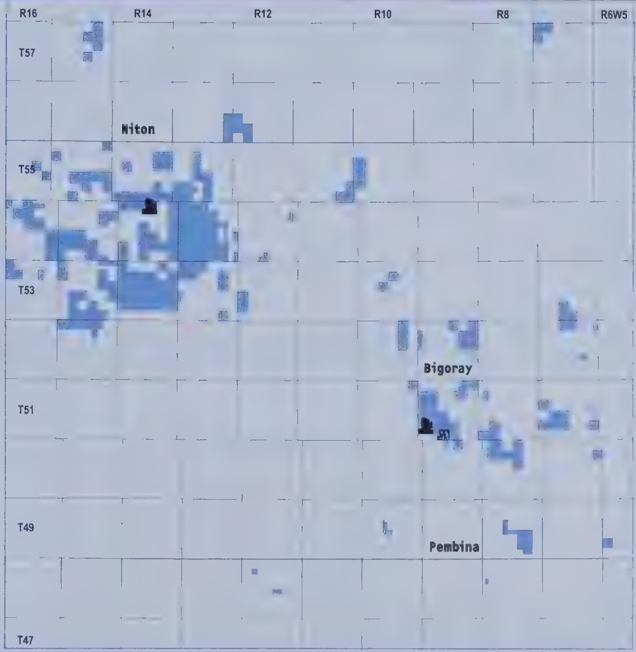
On June 1, 2004, a 45 mmcf/d sweet gas expansion at the Mazeppa plant was completed resulting in 90 mmcf/d sour and 45 mmcf/d sweet processing capacity. Compton gained control and management of the Mazeppa and Gladys gas plants and related infrastructure through the acquisition of the facilities by Mazeppa Processing Partnership in July of 2003. With the completion of the Mazeppa sweet gas expansion, Compton's working interest processing capacity in Southern Alberta is now 200 mmcf/d. Available processing capacity will be sufficient to accommodate the Company's production additions for the next few years. Future expansions, when required, can be undertaken by Compton as operator, ensuring timely completion.

Central Alberta

Central Alberta provides Compton with excellent exploration and development drilling opportunities using similar techniques gained through years of experience from Southern Alberta Deep Basin type, tight gas drilling. Compton holds 757 (407 net) sections of land, the majority located approximately 100 km West of Edmonton. In 2004 we drilled 46 gross (32 net) wells with an 83% success rate. The Company plans to spend $68 million in Central Alberta in 2005 and drill 58 wells.

Niton Gething

The Niton area is characterized by multi-zone, deep basin type targets analogous to the Southern Alberta Hooker area. Compton's primary gas targets include Rock Creek (Jurassic) and Gething. Secondary targets include Bluesky, Viking and Cardium.

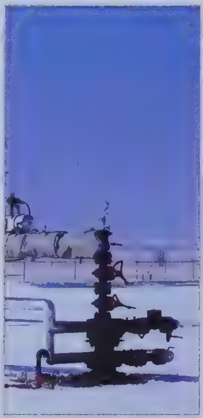


The Company has assembled 126 net sections, with an average working interest of 75%. In 2004, the Company drilled and cased 16 gross (15 net) gas wells. To date, 30 gross gas wells have been drilled with average production of 1 mmcf/d including liquids at an average cost of $1.5 million to drill, complete, equip and tie-in. The Company anticipates the gas-in-place could be in the range of 10-12 bcf per section, with a projected recovery of 75%.

In 2004, Compton received downspacing approval on 18 sections for two wells per section, with further downspacing approval pending. The Company expects two to three wells will be required to fully develop this area, with 26 wells planned in 2005.

During the second quarter of 2004, Compton acquired all of the issued and outstanding shares of Redwood Energy, Ltd., a junior oil and gas company active in the Niton Area. Through the acquisition, we gained undeveloped lands, workover opportunities on existing wells, reserves, production and control of a 35 km gathering system, key to area development.

The Compton owned McLeod River gas plant was operating at maximum capacity in the third quarter of 2004 as a result of the Company's successful drilling program at Niton. The gas plant was expanded from 10 mmcf/d to 20 mmcf/d in the fourth quarter of 2004. A 10 mmcf/d booster compressor at Niton was installed and operational early in the third quarter of 2004.



Peace River Arch

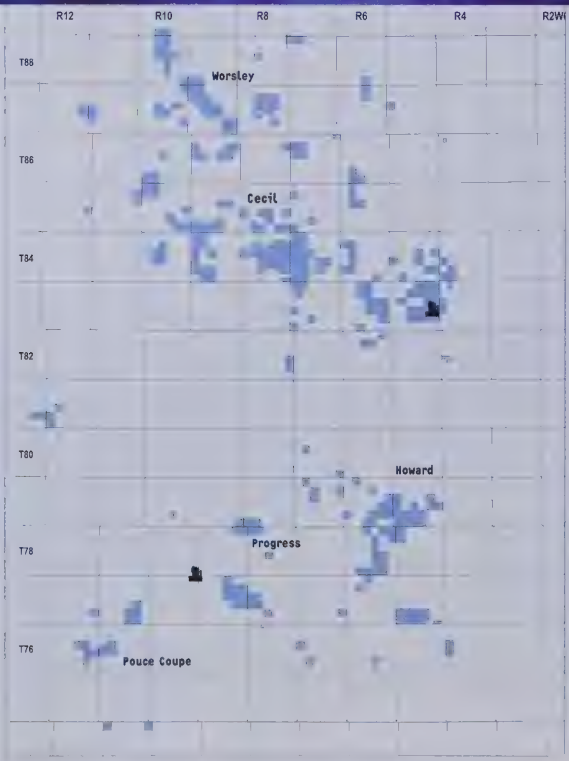
The Peace River Arch area, located north of Grande Prairie, contains multi-zone potential for exploration and development opportunities. This area includes both light oil production at Cecil/Worsley and natural gas exploration at Howard and Pouce Coupe. The Company holds 306 (182 net) sections acres of land in the area. In 2004, Compton drilled 39 gross (26 net) wells in the Arch with a 92% success rate. The Company plans to spend $51 million in the area in 2005 and drill 56 wells.

Cecil/Worsley

Together, the Cecil and Worsley Charlie Lake pools are estimated to hold in excess of 200 million barrels of oil-in-place.

Compton drilled 10 wells at Worsley in 2004, doubling our estimate of the original oil-in-place. As a result of our success with the two existing waterflood pilots, Compton made an application for a pool wide waterflood on the Charlie Lake H and J pool. Approval was granted in February 2005. Waterflooding in the Worsley Charlie Lake H and J pool is projected to increase the ultimate recovery rate from 5-7% to 15-17%.

Pipelines in the Worsley area were expanded to prepare for implementation of the full scale waterflood over the next two years. A battery expansion was also completed to accommodate future drilling plans. In 2005, we anticipate drilling 39 Charlie Lake extension and infill wells at Worsley.



Compton participated in drilling 12 horizontal Charlie Lake oil wells at Cecil in 2004. We have a 40% working interest in the play, which is operated by a major industry partner. The success of the Cecil program has prompted Compton to expand the 2005 drilling program to 20 wells.

Operating Results

Undeveloped Land

In 2004, Compton continued to expand the land base in its core areas. The Company's total land position at December 31, 2004 consisted of 1,122,860 net acres, compared to 1,080,798 net acres the prior year. Land acquisitions during 2004 occurred primarily in the Company's Southern Alberta core area.

Undeveloped land decreased 2% from the prior year as a result of Compton's extensive development drilling in 2004. The Company has an average 72% working interest in its undeveloped land base.

Total Land
(net acres 000s)

	UNDEVELOPED ACRES		TOTAL ACRES	
AREA	GROSS	NET	GROSS	NET
SOUTHERN ALBERTA	492,655	397,799	781,382	638,644
CENTRAL ALBERTA	256,454	164,568	484,789	260,638
PEACE RIVER ARCH	117,040	76,384	195,520	116,379
NORTHERN ALBERTA	113,183	79,030	146,174	93,877
OTHER	40,522	11,648	62,183	13,322
DECEMBER 31, 2004 TOTAL	**1,019,854**	**729,429**	**1,670,048**	**1,122,860**
DECEMBER 31, 2003 TOTAL	1,042,802	767,364	1,601,416	1,080,798
DECEMBER 31, 2002 TOTAL	1,042,923	742,465	1,519,809	975,183

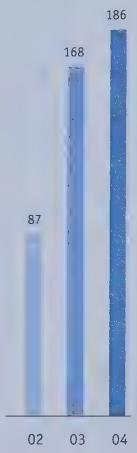
Drilling Activity

Compton drilled 186 gross (146 net) wells in 2004 with a 90% success rate, compared with 168 gross (134 net) wells drilled in 2003.

Of the 186 wells drilled in 2004, 77% were classified as development wells and 23% were classified as exploratory wells, compared to 57% and 43% respectively in 2003. The higher percentage of development wells in the current year reflects the increasing maturity of our oil and gas plays.

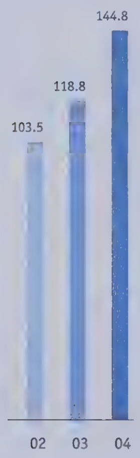
Four wells drilled during the year remain standing cased wells and are awaiting completion and testing. These wells are not included in the following table.

Wells Drilled
(# of gross wells)



YEARS ENDED DECEMBER 31,	NATURAL GAS	OIL	D&A	TOTAL	NET	SUCCESS
SOUTHERN ALBERTA	92	–	7	99	86	93%
CENTRAL ALBERTA	36	1	8	45	31	82%
PEACE RIVER ARCH	8	27	3	38	26	92%
	136	28	18	182	143	90%
STANDING, CASED WELLS				4	3	
2004 TOTAL				**186**	**146**	
2003 TOTAL	131	22	15	168	134	91%
2002 TOTAL	64	14	9	87	64	90%

Proved + Probable Reserves
(MMBOE)



Reserves

In 2003, the Canadian Securities Administrators adopted National Instrument 51-101, "Standards of Disclosure for Oil and Gas Activities". These standards require certain information to be filed on SEDAR, "System for Electronic Disclosure Analysis and Retrieval" and are intended to ensure that all public oil and natural gas companies disclose similar information prepared on the same basis. Compton has filed the required Form NI 51-101 F1 as part of its Annual Information Form ("AIF") which is available on both the SEDAR website and Compton's website. The AIF is very comprehensive, therefore certain information has been extracted with respect to operations and presented in the following sections. All such information is consistent with the Form NI 51-101 F1 filing.

Netherland Sewell Associates, Inc. ("Netherland Sewell") independently evaluated 100% of Compton's reserves.

SUMMARY OF ESTIMATED RESERVE VOLUMES – ESCALATING PRICES AND COSTS

	CRUDE OIL		**NATURAL GAS**		**NGL'S[1]**		**TOTAL**	
AS AT DECEMBER 31, 2004	GROSS[2] (MBBL)	NET (MBBL)	GROSS[2] (BCF)	NET (BCF)	GROSS[2] (MBBL)	NET (MBBL)	GROSS[2] (MBOE)	NET (MBOE)
PROVED								
DEVELOPED PRODUCING	8,577	7,915	361	291	8,464	6,288	77,130	62,782
DEVELOPED NON-PRODUCING	967	865	32	26	505	355	6,792	5,516
UNDEVELOPED	2,815	2,238	52	42	1,430	1,059	12,883	10,260
TOTAL PROVED	12,359	11,018	445	359	10,399	7,702	96,805	78,558
PROBABLE	7,908	6,669	205	169	5,718	4,310	47,972	39,114
TOTAL PROVED PLUS PROBABLE	**20,267**	**17,687**	**650**	**528**	**16,117**	**12,012**	**144,777**	**117,672**
2003 TOTAL PROVED PLUS PROBABLE	12,034	10,179	568	460	12,028	8,917	118,763	95,762

(1) Ngl volumes include sulphur volumes with a conversion rate of one long ton equals one barrel.

(2) Does not include royalty interest equivalent volumes.

In 2004, Compton added approximately 26 mboe, or 264% of 2004 production, to its proved reserves through drilling successes, acquisitions and extensions. Total proved plus probable reserves increased 22% from the prior year to 145 mboe.

Compton's total proved reserve base consists of 75% natural gas and 25% liquids. Proved producing reserves comprise 80% of total proved reserves while total proved reserves account for 67% of the proved plus probable reserves. The Company's reported reserve life index is 10 years and 15 years for total proved and total proved plus probable reserves respectively.

NET PRESENT VALUE OF RESERVES – FORECAST PRICES AND COSTS

	FUTURE NET REVENUE BEFORE INCOME TAXES[1] DISCOUNTED AT A RATE OF		
($000's)	0%	8%	10%
PROVED			
PRODUCING	$ 1,645,719	$ 828,185	$ 748,371
NON-PRODUCING	162,567	89,969	81,164
UNDEVELOPED	289,341	122,652	103,900
TOTAL PROVED	$ 2,097,627	$ 1,040,806	$ 933,435
PROBABLE	1,002,855	435,897	370,710
TOTAL PROVED PLUS PROBABLE	**$ 3,100,482**	**$ 1,476,703**	**$ 1,304,145**

(1) Price forecasts as of December 31, 2004 used in the above evaluations are an average of the forecasts of four major engineering firms in Calgary, Alberta at as December 31, 2004.

Future net revenues are calculated based upon estimated revenue less royalties, operating costs, future development costs and well abandonment costs. Estimated income taxes have not been deducted. The net present value should not be considered the current market value of the Company's reserves or the costs that would be incurred to obtain equivalent reserves.

RESERVE RECONCILIATION - ESCALATING PRICES AND COSTS

	CRUDE OIL AND NGL'S[1]			NATURAL GAS		
	NET PROVED (MBBL)	PROVED PROBABLE (MBBL)	NET PROVED PLUS PROBABLE (MBBL)	PROVED (MMCF)	PROBABLE (MMCF)	NET PROVED PLUS PROBABLE (MMCF)
DECEMBER 31, 2003	14,359	4,876	19,235	324,955	135,347	460,302
EXTENSIONS	–	6,292	6,292	–	75,137	75,137
IMPROVED RECOVERY	4,073	393	4,466	19,633	22	19,655
TECHNICAL REVISIONS	33	(915)	(882)	16,359	(48,574)	(32,215)
DISCOVERIES	1,422	326	1,748	28,057	5,702	33,759
ACQUISITIONS	412	8	420	8,562	1,174	9,736
DISPOSITIONS	–	–	–	(1,395)	–	(1,395)
PRODUCTION	(1,580)	–	(1,580)	(37,142)	–	(37,142)
DECEMBER 31, 2004	**18,719**	**10,980**	**29,699**	**359,029**	**168,808**	**527,837**

(1) Ngl volumes include sulphur volumes with a conversion rate of one long ton equals one barrel.

FINDING & DEVELOPMENT COSTS

Finding, development and acquisition ("FD&A") costs associated with the 2004 exploration and development program, including revisions and changes in future capital, were $14.91/boe on a proved basis and $13.19/boe on a proved plus probable basis. Excluding acquisitions, finding and development ("F&D") costs were $14.96/boe proved and $13.23/boe proved plus probable.

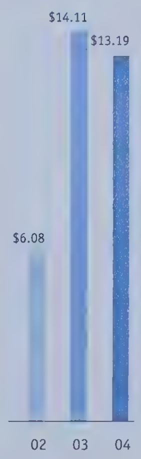
It should be noted that the aggregate of the exploration and development costs incurred in 2004 and the change during the year in estimated future development costs, generally will not reflect total F&D costs related to reserves additions for the year.

($/BOE)	**2004**	2003	2002	3 YEAR AVERAGE	5 YEAR AVERAGE
F&D COSTS, PROVED	**$ 14.96**	$ 21.71	$ 8.16	$ 12.75	$ 11.47
F&D COSTS, PROVED PLUS PROBABLE [1]	**$ 13.23**	$ 14.20	$ 5.79	$ 7.61	$ 7.90
FD&A COSTS, PROVED	**$ 14.91**	$ 20.91	$ 8.15	$ 13.83	$ 12.27
FD&A COSTS, PROVED PLUS PROBABLE [1]	**$ 13.19**	$ 14.11	$ 6.08	$ 11.23	$ 10.70

(1) Calculated using proved plus risked probable (established) reserves for 2002.

Finding and development costs do not include capital expenditures incurred by Mazeppa Processing Partnership of $11 million in 2004 or $65 million in 2003. Changes in future capital of $23 million proved and $167 million proved plus probable were included in FD&A costs.

FD&A Costs
($/boe)



Environment, Health and Safety

The Human Resources, Compensation, Environmental, Health and Safety Committee of the Board has the responsibility to undertake with management those policies, guidelines, practices and procedures designed to manage risk and assure compliance with all applicable workplace, environmental, health and safety laws to protect employees, community residents and the environment.

Environment

Compton believes in the importance of protecting the environment and is committed to conducting all operations in a safe manner that minimizes environmental impact. This commitment is demonstrated through:

- collaborative efforts and support of the Company's employees and contractors to ensure Compton's impact on the environment is assessed and minimized on a yearly basis;
- annual environmental audits to ensure the Company's facilities continually meet or exceed regulatory standards;
- evaluation of the environmental impact of all new projects;
- implementation of internal, strategic management programs; and
- participation in programs for continual improvement set forth by the Canadian Association of Petroleum Producers, Alberta Energy and Utilities Board, Alberta Environmental Protection and other related associations thus demonstrating Compton's commitment to minimizing the Company's footprint on the environment.

Health and Safety

Compton is committed to operate in a safe manner, protecting the health and safety of employees, contractors and community residents. Internal policy requires that all employees, contractors and subcontractors are made aware of and adhere to all Company safety practices, regulatory legislation and applicable industry guidelines. Compton has not experienced a lost time accident since 2001.

Compton is committed to continuous improvements in health and safety practices and undertakes initiatives such as:

- annual safety audits to ensure the Company's facilities continually meet or exceed regulatory standards;
- management systems in place which measure and review Company objectives and targets; and
- openly reporting the Company's health, safety and environmental practices to allow comparison with other oil and gas companies.

Corporate Governance

Compton's Board of Directors believes adopting and upholding the highest standards of corporate governance is critical for the overall success of the Company and to build stakeholder confidence. Sound corporate governance ensures transparency and accountability for Compton's objectives, strategy, controls and overall performance.

Compton's approach to corporate governance aligns with the Guidelines of the Toronto Stock Exchange ("TSX"). On October 29, 2004, the Canadian Securities Administrators released Proposed National Policy 58-201, "Corporate Governance Guidelines" (the "Best Practices Policy") and Proposed National Instrument 58-101, "Disclosure of Corporate Governance Practices" (the "Disclosure Instrument"). The Best Practices Policy, once implemented, will provide guidance on corporate governance practices, following recent U.S. initiatives under the Sarbanes-Oxley Act of 2002 and newly adopted corporate governance rules of the New York Stock Exchange and NASDAQ. The Disclosure Instrument, once implemented, will specifically require issuers to make certain corporate governance disclosures.

Certain provisions of the Sarbanes-Oxley Act of 2002 and specific rules adopted and proposed by the United States Securities and Exchange Commission pursuant to the requirements of the Sarbanes-Oxley Act, are also applicable to Compton due to the issuance of its senior term notes in May 2002.

The Corporate Governance Committee and Board of Directors continuously monitors, reviews and updates the Company's corporate governance policies against the current TSX Guidelines, the newly proposed corporate governance policies, new legislation and regulations, applicable adopted and proposed provisions of the Sarbanes-Oxley Act of 2002 and special interest governance requests. Compton has adopted a policy of early compliance in respect to corporate governance matters and will continue to assess its processes against new regulatory proposals. A thorough discussion of Compton's approach to corporate governance with reference to the Guidelines, the proposed Best Practices Policy and Disclosure Instrument is set forth the Company's Management Proxy Circular, which may be found on the Company's website. The Charters of the Board and its Committees are also located on the Company's website at www.comptonpetroleum.com.

Board Mandate and Composition

The Board of Directors (the "Board") has explicitly assumed responsibility for the stewardship of the Company. The Board shall operate by delegating certain of its authorities to Management, including the day to day conduct of the business of the Company and overseeing the activities of Management, while reserving certain powers for itself. The Board's fundamental objectives are to enhance and preserve long term shareholder value; to provide stewardship in order that the Company meets its obligations on an ongoing basis and to operate in a reliable and safe manner.

The written Charter of the Board explicitly acknowledges responsibility for the stewardship of the company and requires the Board to determine that:

1. the Company has established long-term goals and a strategic planning process;
2. the principal risks of the Company's business are identified and appropriate systems are implemented to manage those risks;
3. there is sufficient succession planning including appointing, training, managing and monitoring Management;
4. the Company has a communications policy;

5. the Company's internal controls and management information systems have sufficient integrity; and
6. the Company's approach to governance issues and the implementation of principles for the management of corporate governance fosters a culture of integrity throughout the Company.

Compton is in full compliance with the provisions of the TSX Guidelines which provide that the board of every company should have a majority of individuals who qualify as unrelated Directors. Compton's Board is comprised of six Directors, five of whom, including the Chairman of the Board, qualify as unrelated Directors. Mr. Sapieha is a related Director because of his position as President & CEO of the Company. The remaining five Directors are independent, unrelated, outside Directors.

An "independent" director is a director who has no direct or indirect material relationship with the Company (a material relationship is a relationship which could, in the view of the Board, reasonably interfere with the exercise of a director's independent judgment). Compton's independent Directors would continue to be defined as independent if the currently proposed amendments to Multilateral Instrument 52-110, "Audit Committees," are implemented.

An "unrelated" Director is a director who is (i) not a member of Management and is free from any interest and any business, family or other relationship which could, or could reasonably be perceived to, materially interfere with the Director's ability to act with a view to the best interests of the Company, other than interests and relationships arising from shareholding; (ii) not currently or has not been, within the last three years, an officer, employee of or material service provider to the Company or any of its subsidiaries or affiliates; and (iii) not a director, officer employee or significant shareholder of an entity that has a material business relationship with the Company.

An "outside" Director is not a member of the Company's Management. Additionally, no Board members sit on other boards together, in order that there are no inter-related interests.

The Board of Directors met 20 times in 2004 and all members attended the meetings with the exception of Mr. Thompson, who attended all meetings but one, and Mr. Smith, who attended all meetings but two.

A full copy of the Charter for the Board of Directors can be found on the Company's website at www.comptonpetroleum.com.

Committees of the Board

Subject to applicable law, the Board may delegate its powers, duties and responsibilities to Committees of the Board. In this regard, the Board has established four standing Committees, the (i) Human Resources, Compensation, Environmental, Health and Safety Committee; (ii) Audit, Finance and Risk Committee; (iii) Engineering, Reserves and Operations Committee; and (iv) Corporate Governance Committee. The mandate of each committee is reviewed annually and is summarized below. All Committees are composed exclusively of independent, outside, unrelated Directors.

HUMAN RESOURCES, COMPENSATION, ENVIRONMENTAL, HEALTH AND SAFETY COMMITTEE

CHAIRMAN: Irvine Koop
MEMBERS: Mel Belich, John Preston, Jeff Smith, John Thomson

The Committee's mandate is to assist the Board in fulfilling its oversight responsibilities with respect to human resources and compensation. Additionally the Committee monitors the environmental, health and safety practices and procedures of the Company for compliance with applicable legislation, conformity with industry standards and prevention or mitigation of loss.

The Committee also has the responsibility to:

1. review and oversee human resources policies of the Company;
2. review succession plans for key Management positions within the Company;
3. develop performance objectives for the CEO and other Officers and assess their performance against such objectives;
4. recommend to the Board, salary and other remuneration for Officers of the Company. The Committee also monitors performance objectives for Officers in order that they are aligned with shareholders' interests and corporate goals;
5. recommend to the Board in respect of all other compensation matters, including long and short term incentives such as bonuses, stock option plans and other benefits; and
6. review and recommend compensation for Board and Committee service.

The Committee fulfills its environmental, health and safety responsibilities by:

1. overseeing the Company's policies and guidelines with respect to environmental, health and safety matters regarding the Company's facilities and operations;
2. undertaking with management those policies, guidelines, practices and procedures designed to manage risk and assume compliance with all workplace, environmental, health and safety laws;
3. reviewing and monitoring the Company's policies, procedures and practices relating to the documentation and reporting of environmental, health and safety regulatory approvals, compliance and incidents; and
4. generally, reviewing the Company's performance related to environment, health and safety and confirming with management that long-range preventative programs are in place.

The Human Resources, Compensation, Environmental, Health and Safety Committee met eight times in 2004 and all members attended the meetings with the exception of Mr. Thompson, who attended all meetings but one.

The full Committee Charter may be found on Compton's website at www.comptonpetroleum.com.

AUDIT, FINANCE AND RISK COMMITTEE

CHAIRMAN: John Thomson

MEMBERS: Mel Belich, Irvine Koop, John Preston, Jeff Smith

The Audit, Finance and Risk Committee is mandated to oversee that Management is responsible for creating and maintaining an effective risk management and internal control framework. This framework provides reasonable assurance that the financial, operational and regulatory objectives of the Company are achieved and that the statutory responsibilities of Board are discharged.

The Committee fulfills its role on behalf of the Board, by overseeing:

1. the review, disclosure and integrity of the Company's financial statements, Management's Discussion and Analysis of financial conditions and results of operations and other financial information;
2. the external auditor's qualifications, independence and performance;

3. the Company's compliance with legal and regulatory requirements;
4. risk management, management information systems, governmental legislation and external business of the Company;
5. the effectiveness and integrity of the Company's system of disclosure controls and internal controls; and
6. reviewing the appointments of the Chief Financial Officer and other key financial executives.

The Committee oversees the operation of an anonymous and confidential toll free telephone number for employees, contractors and others to call with respect to accounting irregularities or ethical violations. The Committee has also established a procedure for the receipt, retention, treatment and regular review of any such reported activities. This telephone number 1-888-929-9093 is published on the Compton's website at www.comptonpetroleum.com.

The Committee met six times in 2004 and all members attended the meetings with the exception of Mr. Smith, who attended all meetings but one.

The full Audit, Finance and Risk Committee Charter may be found on Compton's website at www.comptonpetroleum.com.

ENGINEERING, RESERVES AND OPERATIONS COMMITTEE

CHAIRMAN: Jeff Smith

MEMBERS: Mel Belich, Irvine Koop, John Preston, John Thomson

The Committee's mandate is to review and make recommendations to the Board on the Company's engineering and reserves policies.

The Committee fulfills its oversight role on behalf of the Board and is responsible for:

1. the Company's overall policies and guidelines with respect to engineering, reserves and operations;
2. undertaking with Management all necessary procedures and policies to comply with regulations and guidelines applicable to the Company and enunciated by the applicable regulatory authorities including providing assistance to management in compliance with National Instrument 51-101, preparation of the Statement of Reserves (Form 51-101 F1), Evaluator's Report (Form 51-101 F2) and Management Report (Form NI 51-101 F3);
3. meeting with the Company's Vice President of Operations and Engineering, other senior reserves personnel and the independent reserves evaluator to review and consider the Company's reserves; and
4. reviewing, assisting and making recommendations to the Board in respect of the annual appointment of the Company's independent qualified reserves evaluators;

The Engineering, Reserves and Operations Committee met six times in 2004 and all members attended the meetings, with the exception of Mr. Thompson, who attended all meetings but one.

The full Engineering, Reserves and Operations Committee Charter may be found on Compton's website at www.comptonpetroleum.com.

CORPORATE GOVERNANCE COMMITTEE

CHAIRMAN: Mel Belich

MEMBERS: Irvine Koop, John Preston, Jeff Smith, John Thomson

The Corporate Governance Committee is be responsible for developing the Company's approach to governance issues and to assist the Board in fulfilling its oversight responsibilities with respect to the development and implementation of corporate governance and a view to fostering a culture of integrity within the Company.

The Committee fulfills its oversight role on behalf of the Board and is responsible to:

1. recommend initiatives to maintain high standards of corporate governance;
2. assess the effectiveness and performance of the Board as a whole, its Committees and individual Directors;
3. define and monitor the relationship, roles and authority of the Board and Management;
4. review and evaluate corporate communication policies and practices; and
5. monitor compliance with the Code of Business Conduct and Ethics.

The Committee also has the responsibility to:

1. identify nominees for the Board and its Committees;
2. evaluate (i) the competencies and skills necessary for the Board as a whole, to possess; (ii) the competencies and skills that existing Directors possess; and (iii) the competencies and skills each new nominee will bring to the Board;
3. propose nominees for re-election as Directors by the shareholders at the annual meeting; and
4. propose candidates for appointment to senior Management, executive and Officer positions.

The full Corporate Governance Committee Charter may be found on Compton's website at www.comptonpetroleum.com.

Code of Business Conduct and Ethics

Compton's Code of Business Conduct and Ethics (the "Code") holds the Company's Directors, Officers, employees and consultants to high standards of legal and moral conduct in all areas of operations. In addition to meeting legal and regulatory requirements, the Company strives to conduct all operations fairly and with integrity.

The Board encourages and promotes a culture of ethical business conduct through its guidance provided to Officers and senior members of Management and its oversight of the daily operations of the Company. Additionally, the Whistle Blower Policy (the "Policy") adopted by the Company promotes a culture of openness, honestly and accountability. The Policy establishes procedures for the receipt, retention, treatment and regular review of any unlawful activities, accounting irregularities or ethical violations.

The Board monitors compliance with the Code through the use of an Ethics Hotline, which is an anonymous and confidential toll free telephone number. Additionally, any violations of the Code brought to the attention of Management are reported to the Board. No waivers from the Code were granted to the Company's Directors, Officer, employees or consultants in 2004.

Compton's Code of Business Conduct and Ethics may be viewed on the Company's website at www.comptonpetroleum.com.

Corporate Citizenship

Compton recognizes the importance and positive impact that results from responsible corporate citizenship. The Company is committed to behave ethically and contribute to economic development while improving the quality of life of employees, their families and the local community. Compton believes in giving back to the communities in which it operates and supported numerous local initiatives throughout 2004.

Educational Partnerships

For the past four years, Compton has formed a Corporate/Educational Partnership with a Calgary Board of Education Public School. During the 2003-2004 school year, Compton partnered with Douglas Harkness Elementary School. Compton purchased a new sound system for the school's Performing Arts Program and supported a variety of other student initiatives as identified by the school's staff. As a result of the partnership, Annie Davies, Principal of Douglas Harkness stated, "New and exciting opportunities for children were shaped, and the impact of our joint initiatives will continue to serve our students and their families in the upcoming years."

Compton's Educational Partnership for the 2004-2005 school year is with Harold W. Riley Elementary School. The focus for the partnership will once again be to assist the school staff to enhance the quality of educational opportunities and experiences for the students at Harold W. Riley Elementary School.

Community Partnerships

Compton's Corporate Sponsorship and Donation Programs contributes to charities and community endeavors that enhance the quality of life in the areas where the Company is active.

In 2004, corporate donations were made to: United Way, High River Rotary Club, Nanton Community Health Centre, Okotoks Agricultural Society, Okotoks High School, High River Otters and Tigers Swim Clubs, Foothills Search and Rescue Society, Foothills Special Olympics, Cochrane Search and Rescue Society, Longview Fire Department, Missing Children's Society, Brain Tumour Foundation, Variety Club Children's Charity, Heart and Stroke Foundation, Boys and Girls Club, Multiple Sclerosis Society, CNIB, Aboriginal Foundation, Chrysalis Foundation, CUPS-Community Health Centre, Central Peace Minor Soccer, Okotoks Performing Arts Centre, Tsuu T'ina Nation, Unicef, Cayley 100th Year Celebration, Children's Hospital, Stettler Leisure Centre, Drayton Valley Fieldhouse, Claresholm Health Foundation, Highwood High School, Calgary and Cochrane Humane Societies, Special Olympics-Calgary and Providence Child Centre.

Compton Petroleum and its employees were also active during 2004 in raising funds for the Canadian Cancer Society. Funds were donated to the Cancer Society through Management's participation in a "Head Shave," "Jail-N-Bail" and employee donations.

The Accounts

Advisories

Management's Discussion and Analysis ("MD&A") is intended to provide both an historical and prospective view of the Company's activities. The MD&A was prepared as at March 15, 2005 and should be read in conjunction with the audited consolidated financial statements and related notes for the year ended December 31, 2004. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). A reconciliation to United States GAAP is included in Note 18 to the consolidated financial statements.

Forward Looking Statements

Management's discussion and analysis may contain certain forward looking statements under the meaning of applicable securities laws. Forward looking statements include estimates, plans, expectations, opinions, forecasts, projections, guidance or other statements that are not statements of fact. Although Compton believes that the expectations reflected in such forward looking statements are reasonable, it can give no assurance that such expectations will prove to have been correct. There are many factors that could cause forward looking statements not to be correct, including risks and uncertainties inherent in the Company's business. These risks include, but are not limited to: crude oil and natural gas price volatility, exchange rate fluctuations, availability of services and supplies, operating hazards, mechanical failures, uncertainties in the estimates of reserves and in projections of future rates of production and timing of development expenditures, general economic conditions, the actions or inactions of third-party operator and regulatory pronouncements. The Company's forward looking statements are expressly qualified in their entirety by this advisory.

Non-GAAP Financial Measures

Included in the MD&A and elsewhere in this report are references to terms used in the oil and gas industry such as cash flow, cash flow per share and adjusted net earnings from operations. These terms are not defined by GAAP in Canada and consequently are referred to as non-GAAP measures. Reported amounts may not be comparable to similarly titled measures reported by other companies.

Cash flow should not be considered an alternative to, or more meaningful than, cash provided by operating, investing and financing activities or net earnings as determined in accordance with Canadian GAAP, as an indicator of the Company's performance or liquidity. Cash flow is used by Compton to evaluate operating results and the Company's ability to generate cash to fund capital expenditures and repay debt.

Adjusted net earnings from operations represents net income excluding certain items that are largely non-operational in nature and should not be considered an alternative to, or more meaningful than, net earnings as determined in accordance with Canadian GAAP. Adjusted net earnings from operations is used by the Company to increase comparability of net earnings between periods.

Use of BOE Equivalents

The oil and natural gas industry commonly expresses production volumes and reserves on a barrel of oil equivalent ("boe") basis whereby natural gas volumes are converted at the ratio of six thousand cubic feet to one barrel of oil. The intention is to sum oil and natural gas measurement units into one basis for improved measurement of results and comparisons with other industry participants. In several sections that follow, Compton has used the 6:1 boe measure which is the approximate energy equivalency of the two commodities at the burner tip. However, boe does not represent a value equivalency at the plant gate where Compton sells its production volumes and therefore may be a misleading measure if used in isolation.

Corporate Overview and Strategy

Compton Petroleum Corporation is an independent, public company actively engaged in the exploration, development and production of natural gas, natural gas liquids and crude oil in Western Canada. The Company's activities are concentrated in three core geographic areas, primarily in Alberta, in the Western Canadian Sedimentary Basin. Compton's growth and reserves base have resulted from exploration and development activities, complemented by strategic acquisitions.

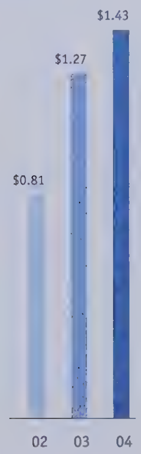
Compton's objective has been and remains that of building an exploration and development company capable of delivering and sustaining long-term growth. Management has adhered to a consistent strategy in pursuing this objective.

Major components of Management's strategy currently include:

- emphasis on natural gas with a particular focus on unconventional tight gas reserves;
- concentration of activities in a limited number of core areas;
- development of technical expertise;
- growth and maintenance of a dominant land position and high working interests in core areas;
- control of infrastructure and operatorship;
- full-cycle exploration; and
- strategic acquisitions.

Cash Flow from Operations
($mm)

Cash Flow per Diluted Share
($/share)



Results of Operations

Cash Flow and Net Earnings

YEARS ENDED DECEMBER 31,	2004	2003	2002
CASH FLOW *($000s)*	**$ 177,131**	$ 154,893	$ 96,072
PER SHARE – BASIC	**$ 1.51**	$ 1.33	$ 0.85
– DILUTED	**$ 1.43**	$ 1.27	$ 0.81
NET EARNINGS *($000s)*	**$ 63,633**	$ 118,880	$ 18,312
PER SHARE – BASIC	**$ 0.54**	$ 1.02	$ 0.16
– DILUTED	**$ 0.51**	$ 0.97	$ 0.16

Cash flow in 2004 rose from 2003 due to higher realized oil and natural gas prices and increased production volumes, somewhat offset by an increase in operating, general and administrative and interest expenses.

Cash flow, as commonly used in the oil and gas industry represents net income before depletion and depreciation, future income taxes and other non-cash expenses. The following table reconciles cash flow from operating activities to cash flow.

YEARS ENDED DECEMBER 31, ($000s)	2004	2003	2002
CASH FLOW FROM OPERATING ACTIVITIES, AS REPORTED	**$ 164,537**	$ 156,211	$ 90,906
CHANGES IN NON-CASH OPERATING WORKING CAPITAL ITEMS	**12,594**	(1,318)	5,166
CASH FLOW	**$ 177,131**	$ 154,893	$ 96,072

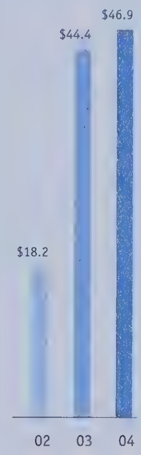
Adjusted Net Earnings from Operations

Net earnings are affected by items of a non-operational nature. To assist in the comparability of net earnings between periods, the Company calculates adjusted net earnings from operations, which eliminates the after tax effect of these items.

The following reconciliation presents the after tax effects of items of a non-operational nature that are included in the Company's financial results.

YEARS ENDED DECEMBER 31, ($000s, except per share amounts)	**2004**	2003	2002
NET EARNINGS, AS REPORTED	**$ 63,633**	$ 118,880	$ 18,312
NON-OPERATIONAL ITEMS, AFTER TAX			
FOREIGN EXCHANGE (GAIN) LOSS	**(11,821)**	(37,761)	1,249
UNREALIZED RISK MANAGEMENT LOSS	**1,338**	–	–
STOCK-BASED COMPENSATION	**2,094**	451	–
EFFECT OF STATUTORY TAX RATE CHANGES			
ON FUTURE INCOME TAX LIABILITIES	**(8,359)**	(37,130)	(1,340)
ADJUSTED NET EARNINGS FROM OPERATIONS	**$ 46,885**	$ 44,440	$ 18,221
PER SHARE – BASIC	**$ 0.40**	$ 0.38	$ 0.16
– DILUTED	**$ 0.38**	$ 0.36	$ 0.15

Adjusted Net Earnings from Operations
($mm)

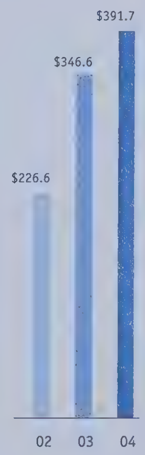


Revenue

YEARS ENDED DECEMBER 31,	**2004**	2003	2002
AVERAGE PRODUCTION			
NATURAL GAS *(mmcf/d)*	**123**	118	112
LIQUIDS (LIGHT OIL & NGLS) *(bbls/d)*	**6,330**	5,924	6,503
TOTAL *(boe/d)*	**26,876**	25,552	25,137
BENCHMARK PRICES			
NYMEX *(U.S.$/mmbtu)*	**$ 6.09**	$ 5.60	$ 3.37
AECO *($/mcf)*	**$ 6.44**	$ 6.35	$ 3.84
WTI *(U.S.$/bbl)*	**$ 41.40**	$ 31.04	$ 26.09
EDMONTON PAR *($/bbl)*	**$ 52.37**	$ 43.14	$ 39.94
REALIZED PRICES [1]			
NATURAL GAS *($/mcf)*	**$ 6.46**	$ 6.27	$ 3.80
LIQUIDS *($/bbl)*	**43.21**	35.59	30.06
TOTAL *($/boe)*	**$ 39.82**	$ 37.16	$ 24.70
REVENUE [1] *($000s)*			
NATURAL GAS REVENUE	**$ 291,565**	$ 269,622	$ 155,234
CRUDE OIL AND NGLS REVENUE	**100,094**	76,943	71,363
TOTAL	**$ 391,659**	$ 346,565	$ 226,597

(1) Restated to exclude realized hedge losses and transportation charges.

Revenue
($mm)



Revenue in 2004 increased from comparable periods due to a combination of increased production volumes and higher realized prices.

	NATURAL GAS	OIL & NGLS	TOTAL
REPORTED 2003 REVENUE [1]	$ 269,622	$ 76,943	$ 346,565
INCREASE IN PRODUCTION VOLUMES	13,790	6,674	20,464
INCREASE IN PRICES	8,153	16,477	24,630
REPORTED 2004 REVENUE	**$ 291,565**	**$ 100,094**	**$ 391,659**

(1) Restated to exclude realized hedge losses and transportation charges.

Average production in 2004 increased 5% from 2003 as a result of the Company's ongoing drilling program and the resolution of facility and pipeline restraints in Southern Alberta. Production growth in Southern Alberta, which accounts for approximately 60% of Compton's total volumes, was constrained by insufficient compression, pipeline and processing capacity in the first half of 2004 and throughout 2003. The expansion of the Mazeppa gas plant was completed on June 1, 2004, resulting in the elimination of these constraints. Production in December 2004 reached approximately 30,000 boe/d, before the disposition of 600 boe/d of production at year end.

Compton's natural gas production is sold under a combination of longer term contracts with aggregators and short term daily or 30 day AECO indexed contracts. Approximately 12% of the Company's natural gas production in 2004 was committed to aggregators, compared to an average of 16% in 2003. The average aggregator price realized in 2004 was approximately $0.32/mcf less than the non-aggregator prices realized during the year.

Compton's crude oil sales are priced at Edmonton postings and are typically sold on 30 day evergreen arrangements. Natural gas liquids are bid out on an annual basis to obtain the most favorable pricing. The Company sells crude oil and natural gas liquids primarily to refineries and marketers of crude oil and natural gas liquids.

From time to time, Compton may enter into hedging arrangements to mitigate commodity price risk. In accordance with Compton's policy, hedging programs will not exceed 50% of non-contracted production. Commodity hedge gains and losses are reflected in "Risk Management" on the consolidated income statements.

Royalties

YEARS ENDED DECEMBER 31, ($000s, except where noted)	**2004**	2003	2002
CROWN ROYALTIES	**$ 75,859**	$ 68,360	$ 38,902
OTHER ROYALTIES	**17,939**	14,706	9,095
TOTAL ROYALTIES	**93,798**	83,066	47,997
ALBERTA ROYALTY TAX CREDIT	**(382)**	(500)	(500)
NET ROYALTIES	**$ 93,416**	$ 82,566	$ 47,497
PERCENTAGE OF REVENUES	**23.9%**	23.8%	21.0%

The Alberta Crown royalty structure imposes higher royalty rates at higher commodity prices and conversely, lower royalty rates at lower commodity prices. Despite higher realized prices in 2004, the Company's average royalty rate was only marginally higher than in 2003 due to a gas cost allowance adjustment recorded in the second quarter of 2004.

Operating Expenses

YEARS ENDED DECEMBER 31,	**2004**	2003 (1)	2002 (1)
OPERATING EXPENSES *($000s)*	**$ 55,655**	$ 49,916	$ 45,546
OPERATING EXPENSES PER BOE *($/boe)*	**$ 5.66**	$ 5.35	$ 4.96

(1) Restated to exclude transportation charges.

Operating costs per boe increased from 2003 due to an overall rise in the cost of goods and services in the oil and gas industry and additional field staff required for expanding operations.

Transportation

YEARS ENDED DECEMBER 31,	**2004**	2003	2002
TRANSPORTATION COSTS *($000s)*	**$ 8,595**	$ 8,447	$ 8,167
TRANSPORTATION COSTS PER BOE *($/boe)*	**$ 0.87**	$ 0.91	$ 0.89

Effective for 2004, Compton's transportation costs are disclosed separately in the consolidated statements of earnings. Previously, transportation was partially recorded as a reduction of revenue and partially as an increase in operating expenses. For comparative purposes, 2003 and 2002 amounts have been reclassified.

Compton incurs charges on the transportation of its production from the wellhead to the point of sale. Pipeline tariffs and trucking rates for liquids are primarily dependent upon production location and distance from the sales point. Government regulated pipeline tolls dictate transportation rates for natural gas in Alberta. Compton's transportation rates in 2004 have remained relatively consistent with prior years on a per boe basis.

General and Administrative Expenses

YEARS ENDED DECEMBER 31, ($000s, except where noted)	**2004**	2003	2002
GENERAL AND ADMINISTRATIVE EXPENSES	**$ 24,663**	$ 20,355	$ 16,145
CAPITALIZED GENERAL AND ADMINISTRATIVE EXPENSES	**(2,683)**	(3,321)	(2,689)
OPERATOR RECOVERIES	**(6,765)**	(4,828)	(3,611)
TOTAL GENERAL AND ADMINISTRATIVE EXPENSES	**$ 15,215**	$ 12,206	$ 9,845
GENERAL AND ADMINISTRATIVE PER BOE *($/boe)*	**$ 1.55**	$ 1.31	$ 1.07

Additional full time employees required due to the expanded activities of the Company, additional regulatory and reporting related costs and higher insurance costs contributed to increased G&A in 2004.

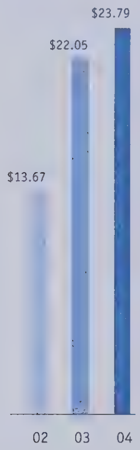
Interest Expense

YEARS ENDED DECEMBER 31, ($000s)	**2004**	2003	2002
INTEREST EXPENSE	**$ 33,733**	$ 30,595	$ 23,197
LESS: FINANCE CHARGES	**(2,790)**	(2,273)	(1,926)
REALIZED GAIN ON INTEREST RATE SWAP	**(2,522)**	(1,365)	(3,067)
	$ 28,421	$ 26,957	$ 18,204
AVERAGE DEBT	**$ 398,170**	$ 339,190	$ 265,605
AVERAGE INTEREST RATE	**7.1%**	7.9%	6.9%

Interest expense in 2004, excluding finance charges and gains realized on the Company's interest rate swap, was consistent with the prior year. Compton incurred higher average debt throughout 2004 however the impact on interest expense was offset by lower interest rates. Debt levels in 2004 were elevated as total capital expenditures in 2004 exceeded the current year's cash flow.

Netbacks

Field Netbacks
($/boe)(6:1)



YEARS ENDED DECEMBER 31,	2004 NATURAL GAS ($/MCF)	2004 LIQUIDS ($/BBL)	2004 TOTAL ($/BOE)	2003 [1] TOTAL ($/BOE)	2002 TOTAL ($/BOE)
REALIZED PRICE [2]	**$ 6.46**	**$ 43.21**	**$ 39.82**	$ 37.16	$ 24.70
ROYALTIES, NET	**(1.58)**	**(9.50)**	**(9.50)**	(8.85)	(5.18)
OPERATING EXPENSES [3]	**(0.94)**	**(5.66)**	**(5.66)**	(5.35)	(4.96)
TRANSPORTATION	**(0.15)**	**(0.87)**	**(0.87)**	(0.91)	(0.89)
FIELD OPERATING NETBACK	**$ 3.79**	**$ 27.18**	**$ 23.79**	$ 22.05	$ 13.67
GENERAL AND ADMINISTRATIVE			**(1.55)**	(1.31)	(1.07)
INTEREST			**(3.43)**	(3.28)	(2.53)
CURRENT TAXES			**(0.28)**	(0.35)	(0.16)
CASH FLOW NETBACK			**$ 18.53**	$ 17.11	$ 9.91

(1) Restated to include the impact of MPP.
(2) Restated to exclude realized hedge gains and losses and transportation charges.
(3) Restated to exclude transportation charges.

Risk Management

The Company's financial results are impacted by external market risks associated with fluctuations in commodity prices, interest rates and the Canadian/U.S. exchange rate. The Company utilizes various financial instruments for non-trading purposes to manage and partially mitigate its exposure to these risks. Commodity price contracts are employed to manage risk associated with price volatility in order to protect cash flow for the Company's capital expenditure program.

Concurrent with the closing of the senior notes offering in May of 2002, the Company negotiated a cross currency interest rate swap. The swap, which converted fixed rate U.S. dollar interest obligations into floating rate Canadian dollar interest obligations, was entered into to fix the exchange rate on interest payments and also to take advantage of lower floating interest rates.

On January 1, 2004, the Company adopted the CICA's Accounting Guideline 13, "Hedging Relationships" (the "Guideline") and EIC 128, "Accounting for Trading, Speculative or Non-Hedging Derivative Financial Instruments". Financial instruments that are not designated or do not qualify as hedges under the Guideline are recorded at fair value on the Company's consolidated balance sheets, with subsequent changes recognized in consolidated net earnings. Fair value is determined on a mark-to-market basis utilizing quoted market prices. Previously, gains and losses resulting from financial instruments were recognized only when realized.

Under EIC 128, unrealized gains or losses relating to contracts in effect at the end of a period are recognized and included in risk management activity together with realized gains and losses. Compton elected not to designate and financial instruments as hedges and therefore follows EIC 128 accounting.

Adoption of EIC 128 resulted in the following:

YEARS ENDED DECEMBER 31, ($000s)	**2004**	2003	2002
COMMODITY CONTRACTS			
REALIZED LOSS (GAIN)	**$ 9,151**	$ 5,497	$ (1,357)
UNREALIZED (GAIN)	**(1,985)**	–	–
CROSS CURRENCY INTEREST RATE SWAP			
REALIZED (GAIN)	**(2,522)**	(1,365)	(3,067)
UNREALIZED LOSS	**4,164**	–	–
TOTAL RISK MANAGEMENT LOSS (GAIN)	**$ 8,808**	$ 4,132	$ (4,424)
REALIZED LOSS (GAIN)	**$ 6,629**	$ 4,132	$ (4,424)
UNREALIZED LOSS	**2,179**	–	–
TOTAL RISK MANAGEMENT LOSS (GAIN)	**$ 8,808**	$ 4,132	$ (4,424)

Depletion and Depreciation

YEARS ENDED DECEMBER 31,	**2004**	2003	2002
TOTAL DEPLETION AND DEPRECIATION *($000s)*	**$ 82,554**	$ 61,749	$ 55,473
DEPLETION AND DEPRECIATION PER BOE *($/boe)*	**$ 8.39**	$ 6.62	$ 6.05

Depletion and depreciation rates have risen in 2004 as the result of higher capital expenditures incurred for the exploration for probable reserves and optimization of proved developed reserves, resulting in an overall increase in FD&A costs.

Foreign Exchange

The foreign exchange gain on the consolidated statements of income is primarily an unrealized gain resulting from the translation of the Company's U.S. $165 million senior term notes. The notes are recorded on the consolidated balance sheets at the year end exchange rate with any differences booked as an unrealized foreign exchange gain or loss. The Canadian dollar closed in 2004 at U.S. $0.8308 compared to U.S. $0.7738 at December 31, 2003, resulting in a $15 million foreign exchange gain in 2004. The cumulative unrealized gain from the date of issue of the notes in May 2002 is $61 million. The Company is currently considering options to crystallize the unrealized gain.

Stock-Based Compensation

YEARS ENDED DECEMBER 31,	**2004**	2003
OPTIONS GRANTED *(000s)*	**2,549**	1,503
WEIGHTED AVERAGE FAIR VALUE OF OPTIONS GRANTED *($/share)*	**$ 3.70**	$ 3.01
STOCK-BASED COMPENSATION EXPENSE *($000s)*	**$ 3,410**	$ 760

Compton has a stock option plan for Directors, Officers and employees. The plan is designed to attract, motivate and retain outstanding individuals and to align their success with that of the Shareholders through achieving corporate objectives. The fair value of options granted is estimated on the date of grant using the Black-Scholes option pricing model and the associated compensation expense is recognized over the vesting period.

Taxes

CURRENT TAXES

Current income taxes include federal capital tax. This tax is non-deductible and increases as the capital resources of the Company increase. In 2004, federal capital tax remained relatively consistent with 2003. The higher capital resources of the Company were offset by a rate reduction from 0.225% to 0.200%, as part of the phased elimination of federal capital tax by 2008.

FUTURE INCOME TAXES

The Company's future income taxes were $33 million in 2004, compared to $20 million in 2003. Future taxes in 2003 benefited from a $37 million recovery due to statutory rate reductions compared to an $8 million recovery in 2004.

CORPORATE TAX RATES

YEARS ENDED DECEMBER 31,	**2004**	2003	2002
STATUTORY RATE	**38.6%**	40.6%	42.1%
EFFECTIVE RATE	**35.0%**	16.4%	52.2%

A reconciliation of the Company's effective tax rate to the statutory rate may be found in Note 14(a) to the consolidated financial statements.

TAX POOLS

The following table summarizes Compton's estimated tax pool balances by classification.

AS AT JANUARY 1, 2005	AVAILABLE BALANCE ($000s)	MAXIMUM ANNUAL DEDUCTION
CANADIAN EXPLORATION EXPENSE	$ 35,585	100%
CANADIAN DEVELOPMENT EXPENSE	159,127	30%
CANADIAN OIL AND NATURAL GAS PROPERTY EXPENSE	182,399	10%
UNDEPRECIATED CAPITAL COST	129,047	4%-100%
TOTAL	$ 506,158	

A significant portion of the Company's taxable income is generated by a wholly owned partnership. Income taxes are incurred on the partnership's earnings in the year following its inclusion in the Company's consolidated net earnings.

Consolidated earnings before income taxes include $178 million (2003 - $166 million) of partnership earnings that will be included in the following year's income for income tax purposes. Future income taxes include $67 million (2003 - $63 million) as a result of this deferral of partnership earnings.

Based upon planed capital expenditure programs and current commodity price assumptions, the Company will not be cash taxable until 2007.

Capital Expenditures

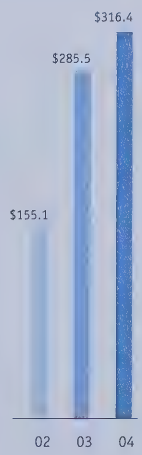
In 2004, the Company continued to invest in land and production facilities together with exploratory and development drilling necessary for future growth. Total capital expenditures in the current year were $316 million, including the acquisition of Redwood Energy, Ltd. and Mayfair Energy Ltd.

Drilling and completions expenditures rose from the prior year due to an increase in net wells drilled. Compton drilled 146 net wells compared to 134 wells in 2003. Drilling in the current year included additional wells at Hooker and Callum, which are more costly due to their depth. Additionally, drilling costs are increasing across the industry due to high demand for rigs, services and materials.

Facilities expenditures in 2004 included an expansion of the Niton gas plant from 10 mmcf/d to 20 mmcf/d; the installation of a 10 mmcf/d booster compressor at Niton; expansion of pipelines and a battery in the Worsley area; installation of compression plus a six inch pipeline from Brant to the Shouldice Gas Plant; and de-bottlenecking and expansion of the Hooker pipeline system.

YEARS ENDED DECEMBER 31,	2004 ($000s)	%	2003 ($000s)	%	2002 ($000s)	%
DRILLING AND COMPLETIONS	**$ 175,003**	**57**	$ 126,308	57	$ 75,369	48
LAND AND SEISMIC	**38,326**	**12**	37,128	17	29,096	19
FACILITIES	**68,861**	**23**	46,068	21	21,714	14
ACQUISITIONS, NET	**1,938**	**1**	11,224	5	28,929	19
SUB-TOTAL	**284,128**	**93**	220,728	100	155,108	100
CORPORATE ACQUISITIONS	**20,887**	**7**	–	–	–	–
SUB-TOTAL	**305,015**	**100**	220,728	100	155,108	100
MPP	**11,386**		64,755		–	
TOTAL CAPITAL EXPENDITURES	**$ 316,401**		$ 285,483		$ 155,108	

Capital Expoenditures
($mm)



Liquidity and Capital Resources

AS AT DECEMBER 31, ($000s, except where noted)	2004	2003	2002
WORKING CAPITAL	**$ (1,382)**	$ (21,843)	$ (32,139)
CURRENT BANK DEBT	**220,000**	164,500	40,000
SENIOR TERM NOTES	**198,594**	213,246	260,634
	$ 417,212	$ 355,903	$ 268,495
SHAREHOLDERS' EQUITY			
CAPITAL STOCK	**$ 135,526**	$ 131,577	$ 128,079
CONTRIBUTED SURPLUS	**3,840**	760	–
RETAINED EARNINGS	**284,712**	224,569	112,039
	$ 424,078	$ 356,906	$ 240,118
DEBT TO CASH FLOW (1) (2)	**2.36**	2.44	3.13
DEBT TO EBITDA (3)	**2.44**	2.02	2.54
DEBT TO BOOK CAPITALIZATION (1)	**50%**	51%	56%
DEBT TO MARKET CAPITALIZATION (1)	**25%**	35%	34%

(1) Debt includes current and long-term portion.
(2) Based on trailing 12 month cash flow.
(3) EBITDA represents earnings from operations before interest, taxes, depletion and depreciation and unrealized foreign exchange gain.

At year end, the Company had drawn $220 million on its available $240 million syndicated credit facility. Debt levels at December 31, 2004 increased over 2003 as total capital expenditures exceeded the current year's cash flow.

The principal of the senior term notes remains fixed at U.S. $165 million. The value of the notes shown on the consolidated balance sheets varies in response to movement in the Canadian/U.S. dollar exchange rate.

The Company targets a debt to cash flow ratio of less than 2:1. Based upon the company's 2005 budget and, the equity issue noted below and proceeds of $50 million from planned property sales, the Company projects a debt to cash flow ratio of 1.8:1 at December 31, 2005.

On February 18, 2005, Compton issued 7.5 million common shares at a price of $12.00 per share for gross proceeds of $90 million. Funds from the issue were used initially to repay a portion of the Company's current indebtedness and thereafter to expand and accelerate our 2005 capital expenditure program. Additionally, Compton plans to dispose of a number of minor, non-core property interests in 2005. Proceeds are expected to be in the range of $50 to $60 million.

The Company is considering replacing up to $100 million of revolving, secured borrowing based debt with longer, fixed term subordinated debt. This will provide additional availability under existing credit facilities and reduce Compton's dependence on revolving demand bank debt. Various options are being considered with the goal of finalizing the restructuring in conjunction with the annual review of our existing credit facilities in the second quarter of 2005.

Compton expects funds generated from operations, proceeds from the common share equity issue in February 2005, minor non-operated property dispositions and funds available under the Company's existing bank credit facilities, will be sufficient to finance operations and planned capital expenditures of $390 million in 2005.

Contractual Obligations

As part of normal business, Compton has entered into arrangements and incurred obligations that will impact our future operations and liquidity, some of which are reflected as liabilities in the consolidated financial statements. The following table summarizes the Company's contractual obligations as at December 31, 2004.

	PAYMENTS DUE BY PERIOD			
($000s)	LESS THAN 1 YEAR	1-3 YEARS	4-5 YEARS	AFTER 5 YEARS
PAYMENT OF SENIOR NOTES	$ –	$ –	$ 198,594	$ –
PARTNERSHIP DISTRIBUTIONS	9,172	27,516	3,057	–
OPERATING LEASES	5,025	15,533	–	–
OFFICE RENT	1,268	1,605	–	–
CAPITAL LEASE OBLIGATIONS	38	50	–	–
OTHER LONG-TERM OBLIGATIONS	98	193	–	–
TOTAL	$ 15,601	$ 44,897	$ 201,651	$ –

The Company has the ability and intends to extend the term of its current borrowings of $220 million on an ongoing basis under its syndicated credit facility and therefore repayment of the facility is not included in the schedule of contractual obligations above.

Commitments

To prevent the expiration of undeveloped lands, the Company anticipates approximately $9 million of work commitments will be required in 2005. These commitments have been included in our 2005 capital expenditure budget.

Guidance for 2005

Compton's budget for 2005 is based upon the following:

	2005 BUDGET RANGE
CAPITAL EXPENDITURES *($millions)*	$ 390
GROSS WELLS	390
AVERAGE PRODUCTION	
NATURAL GAS *(mmcf/d)*	144 – 148
LIQUIDS *(bbls/d)*	7,500 – 7,900
TOTAL *(boe/d)*	31,500 – 32,500
CASH FLOW *($millions)*	$ 230 – $ 240
PER SHARE – BASIC (1)	$ 1.84 – $ 1.92

(1) Based on shares outstanding as at March 15, 2005.

The Company's budgeted cash flow for 2005 is based upon the following assumptions:

		BENCHMARK	REALIZED CDN.
NATURAL GAS ($/MCF)	AECO	$ 6.25 CDN	$ 6.47
CRUDE OIL ($/BBL)	WTI	$40.00 U.S.	$ 42.07

The average Canadian/U.S. exchange rate was budgeted at $0.83 U.S. = $1.00 Cdn.

Cash Flow Sensitivities for 2005

($millions)	
CHANGE OF CDN $0.25/MCF IN THE BENCHMARK AECO NATURAL GAS PRICE	$ 11
CHANGE OF U.S. $1.00/BARREL IN THE BENCHMARK WTI OIL PRICE	$ 2
CHANGE OF U.S. $0.01 IN THE CANADIAN/U.S. EXCHANGE RATE	$ 1

2005 Capital Expenditures

Compton has budgeted for $390 million of capital expenditures in 2005, to be funded through a combination of cash flow, equity, minor property sales and debt as follows:

($millions)	
CASH FLOW	$ 230 – $ 240
EQUITY ISSUE - NET PROCEEDS	$ 86
PROPERTY SALES	$ 50 – $ 60
DEBT	$ 5 – $ 25

In the event of significant decreases in commodity prices, increases in exploration costs or an overall economic downturn, the Company's capital expenditure program can be quickly adjusted to reduce capital spending.

Additional Disclosures

Critical Accounting Estimates

Critical accounting estimates require Management to make assumptions regarding matters that are uncertain at the time the estimate is made and may have a material impact on the financial condition of the Company. A comprehensive discussion of Compton's significant accounting policies may be found in Notes 1 and 2 to the consolidated financial statements.

OIL AND NATURAL GAS RESERVES

The independent petroleum engineering and geological consulting firm of Netherland Sewell evaluated and reported on 100% of Compton's oil and natural gas reserves.

The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. The Company expects that its estimates of reserves will change with updated information from the results of future drilling, testing or production levels. Such revisions could be upward or downward. Reserve estimates have a material impact on depletion and depreciation, asset retirement expenses and impairment costs which could possibly have a material impact on consolidated net income.

DEPLETION

Capitalized costs and estimated future expenditures to develop proved reserves, including abandonment costs, are depleted based on the proportion of estimated proved oil and natural gas reserves produced during the year compared to total proved reserves. Investments in unproved properties and major development projects are not amortized until proved reserves associated with the projects can be determined or until impairment occurs. If it is determined that properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized.

In 2004, Compton incurred $83 million of depletion and depreciation. If the proved reserves of the Company were to vary by 5%, the depletion and depreciation expense would change by approximately $1 million and consolidated net income after tax would change by approximately $780,000.

IMPAIRMENT

In applying the full cost method of accounting, Compton periodically calculates a ceiling or limitation on the amount that property and equipment may be carried for on the consolidated balance sheets. An impairment exists if the undiscounted future net cash flows from proved reserves at future commodity prices plus the cost of undeveloped properties is less than the carrying value of the capitalized costs. As at December 31, 2004 the ceiling amount calculated was approximately $1 billion in excess of the carrying value of the costs capitalized.

If an impairment is found to exist, the impaired properties are written down to their fair value. The fair value of the assets is calculated based on future net cash flows from proved plus probable reserves, discounted at a risk free interest rate using future commodity prices, plus the cost of undeveloped properties. An impairment may result in a material loss for a particular period; however, future depletion and depreciation expense would be reduced as a result.

Assumptions about reserves and future prices are required to calculate future net cash flows. The assumptions made to estimate reserves have been discussed above. There is significant uncertainty regarding forecasting future commodity prices due to economic and political uncertainties. Future prices are derived from a consensus of price forecasts among recognized reserve evaluators. Estimates of future cash flows assume a long-term price forecast and current operating costs per boe plus an inflation factor.

It is difficult to determine and assess the impact of a decrease in proved reserves on impairment. The relationship between reserve estimates and the estimated undiscounted cash flows, and the nature of the property-by-property impairment test, is complex. As a result, it is not possible to provide a reasonable sensitivity analysis of the impact that a reserve estimate decrease would have on impairment. No material downward revisions to the Company's reserves are anticipated.

ASSET RETIREMENT OBLIGATION

Compton is required to remove production equipment, batteries, pipelines, gas plants and restore land at the end of oil and natural gas operations. The Company estimates these costs in accordance with existing laws, contracts and other policies. These obligations are initially measured at fair value, which is the discounted future value of the liability. This fair value is capitalized as part of the cost of the related assets and amortized over the useful life of the assets.

An annual increase to the liability is recorded to recognize the passage of time and the impending settlement of the obligation. The liability is impacted by any changes in the assumptions used in the asset retirement obligation ("ARO") calculation. Adjustments to the estimate will be recorded as an accretion expense on the consolidated statements of earnings.

In the future, the Company's depletion expense will be reduced since the discounted value of the liability on the future consolidated financial statements will be depleted, rather than the undiscounted value previously depleted. The lower depletion expense will be offset by the addition of the accretion expense.

An independent environmental consulting firm was hired to assist Management in the estimation of asset removal costs. The ARO cost calculations were derived from a combination of actual third party cost quotes, Alberta Energy and Utilities Board cost models and typical industry experience and practices. The deemed ARO liability for wells and facilities is the sum of the calculated abandonment and reclamation liabilities adjusted for designated status as active, inactive, abandoned or problem site. Information regarding environmental remediation costs and other liability issues for site specific concerns were derived from a review of historical audits and assessment reports for sites and facilities. An inflation rate of 2.0% and a credit adjusted risk free interest rate of 10.8% was used in Compton's fair value calculation.

Estimating future asset removal costs is difficult and requires Management to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as well as regulatory, political, environmental, safety and public relations considerations. As a result, it is not possible to provide a reasonable analysis of the impact that changes in removal costs would have on the asset retirement obligation. If the inflation rate assumed in the ARO calculation changed by 1%, the ARO obligation would vary by $3 million. Additionally, a 1% change in the credit adjusted risk free interest discount rate would result in a $2 million change to the ARO liability.

Changes in Accounting Policy

The Canadian Institute of Chartered Accountants adopted several new accounting standards that became effective in 2004. Compton chose to early adopt the Stock Based Compensation, Asset Retirement Obligations and Oil & Gas Full Cost Accounting standards in the preparation of its 2003 consolidated financial statements. The only new standard affecting the preparation of the 2004 consolidated financial statements is Hedge Accounting.

HEDGE ACCOUNTING

In December 2001, the CICA modified Accounting Guideline 13, "Hedging Relationships" ("AcG-13"). The Guideline establishes certain conditions where hedge accounting may be applied, effective for fiscal years beginning on or after July 1, 2003. Additionally, the CICA's Emerging Issues Committee ("EIC") amended their guidance in EIC 128, "Accounting for Trading, Speculative or Non-Trading Derivative Financial Instruments," to require that all derivative instruments that do not qualify for hedge accounting or are not designated as hedges, be recorded on the consolidated balance sheets with changes in fair value recognized in earnings.

Compton adopted the modified Guideline effective January 1, 2004 and elected not to designate any of its current risk management activities as accounting hedges under AcG-13. The Company currently accounts for all derivatives using the mark-to-market accounting method. The impact on the Company's consolidated financial statements at January 1, 2004 was an increase in liabilities of $11 million and a deferred loss of $11 million, which will be recognized as the contracts expire.

Financial Conditions and Risks

Compton's operations are subject to risks normally associated with the oil and natural gas industry. The Company is exposed to financial risks including commodity price fluctuations and changing expenditure costs due to shifts in market conditions. Commodity prices are driven by supply, demand and market forces outside our influence. However, our product mix is diversified to minimize exposure to price movements in any one commodity. Sales of oil and natural gas are aimed at various markets to avoid undue exposure to any one market. When appropriate, we ensure that parental guarantees or letters of credit are in place to minimize the impact in the event of default.

Compton monitors and focuses its expenditures to reflect commodity prices and production changes, as well as continuously scrutinizing market conditions and opportunities. From time to time the Company will employ financial instruments to manage exposure related to Canadian/U.S. dollar exchange rates and commodity prices.

The Company has commodity and fixed-price contracts outstanding, as outlined below:

COMMODITY	TYPE	TERM	VOLUME	AVERAGE PRICE	INDEX
NATURAL GAS	COLLAR	NOV. 2004 - MARCH 2005	25,000 GJ/D	CDN.$7.15 - $11.01	AECO
	COLLAR	APR. 2005 - OCT. 2005	15,000 GJ/D	CDN.$5.92 - $8.45	AECO
CRUDE OIL	COLLAR	JAN. 2005 - DEC. 2005	1,000 BBLS/D	U.S.$35.00 - U.S.$48.75	WTI
	COLLAR	FEB. 2005 - DEC. 2005	500 BBLS/D	U.S.$43.00 - U.S.$49.51	WTI

The Company considers longer term contracts with suppliers where appropriate, to mitigate shifts in costs resulting from changes in industry and market conditions. Compton has no control over government intervention or taxation levels on the industry.

In the future, it is likely that we will be required to raise additional capital via debt and/or equity financings in order to fully realize our strategic goals and business plans. Compton's ability to raise additional capital will depend upon a number of factors, such as general economic and market conditions that are beyond our control. If we are unable to obtain additional financing or to obtain it on favorable terms, the Company might be required to forego attractive business opportunities. Compton is committed to maintaining a strong balance sheet, combined with a flexible capital expenditure program that can be adjusted to capitalize on or reflect acquisition opportunities or a tightening of liquidity sources.

RISK MANAGEMENT

From time to time, Compton enters into hedge transactions to manage fluctuations in commodity prices and foreign currency. The Company does not participate in derivative or other financial instruments for trading purposes and commodity price contracts may not exceed 50% of non-contracted production. Management considers an abundance of information from a variety of sources before entering into a financial transaction. The Audit, Finance and Risk Committee of the Board of Directors regularly reviews the Company's hedging strategies and transactions.

Interest Rate Risk Management

Concurrent with the closing of the senior notes offering in May of 2002, the Company negotiated a cross currency interest rate swap. The swap, which converted fixed rate U.S. dollar interest obligations into floating rate Canadian dollar interest obligations, was entered into to fix the exchange rate on interest payments and to take advantage of lower floating interest rates.

The terms of the swap correlates with the terms of the debt agreement and has resulted in an effective interest rate of 7.24% (2003 - 7.85%). At December 31, 2004 there was an unrealized hedge loss of $4 million (2003 - $9 million), as calculated on a mark-to-market basis by the issuer of the instrument.

Foreign Currency Exchange Rate Risk Management

The Company is exposed to fluctuations in the exchange rate between the Canadian dollar and the U.S. dollar. Crude oil and to a large extent natural gas prices are based upon reference prices denominated in U.S. dollars, while the majority of our expenses are denominated in Canadian dollars. When appropriate, Compton enters into agreements to fix the Canadian/U.S. dollar exchange rate in order to manage the risk. No foreign currency agreements were in place in 2004. In 2003, a $2 million gain was realized and included in revenue as a result of foreign currency contracts.

Commodity Price Risk Management

Compton enters into commodity price contracts to hedge anticipated sales of oil and natural gas production to protect cash flows for our capital expenditure programs. Commodity price risk is actively managed by using costless collars and by balancing physical and financial contracts in terms of volumes, timing of performance and delivery obligations. Net open positions may exist or may be established to take advantage of market conditions. Net income for the year ended December 31, 2004 include losses of $7 million (2003 - $5 million loss; 2002 - $1 million gain) on these transactions.

Selected Quarterly Information

The following tables set out selected quarterly financial information of the Company for the last two fiscal years.

	THREE MONTHS ENDED				YEAR ENDED
($000s, except where noted)	MAR. 31, 2004	JUN. 30, 2004	SEP. 30, 2004	DEC. 31, 2004	DEC. 31, 2004
AVERAGE PRODUCTION *(boe/d)*	25,717	26,295	27,268	28,204	26,876
AVERAGE PRICING (2) *($/boe)*	$ 38.04	$ 41.43	$ 40.78	$ 39.00	$ 39.82
TOTAL REVENUE (1)	$ 89,031	$ 99,140	$ 102,299	$ 101,189	$ 391,659
CASH FLOW	$ 40,860	$ 47,698	$ 46,844	$ 41,729	$ 177,131
PER SHARE – BASIC	$ 0.35	$ 0.41	$ 0.40	$ 0.35	$ 1.51
– DILUTED	$ 0.33	$ 0.39	$ 0.38	$ 0.33	$ 1.43
NET INCOME	$ 22,301	$ 2,978	$ 21,977	$ 16,377	$ 63,633
PER SHARE – BASIC	$ 0.19	$ 0.03	$ 0.19	$ 0.14	$ 0.54
– DILUTED	$ 0.18	$ 0.02	$ 0.18	$ 0.13	$ 0.51

(1) Restated to exclude transportation and realized hedging gains and losses.

(2) Restated to exclude realized hedge gains and losses.

In 2004, strong overall commodity prices and increasing production increased total revenue.

Net income in the second quarter of 2004 was impacted by an unrealized risk management loss of $7 million after tax and an unrealized foreign exchange loss of $4 million after tax. Net income for the year was lower than in 2003 as the prior year benefited from a $39 million after tax, unrealized foreign exchange gain on the translation of the Company's U.S. denominated debt, compared to a $14 million after tax gain in 2004. Net income in 2003 also included a $37 million future income tax recovery in the second quarter due statutory income tax rate changes compared to an $8 million gain in the current year.

	THREE MONTHS ENDED				YEAR ENDED
($000s, except where noted)	MAR. 31, 2003	JUN. 30, 2003	SEP. 30, 2003 (1)	DEC. 31, 2003	DEC. 31, 2003
AVERAGE PRODUCTION *(boe/d)*	25,853	25,659	24,219	26,484	25,552
AVERAGE PRICING (3) *($/boe)*	$ 42.25	$ 37.29	$ 35.07	$ 34.08	$ 37.16
TOTAL REVENUE (2)	$ 98,306	$ 87,063	$ 78,150	$ 83,047	$ 346,565
CASH FLOW	$ 48,038	$ 39,610	$ 34,525	$ 32,625	$ 154,893
PER SHARE – BASIC	$ 0.41	$ 0.34	$ 0.30	$ 0.28	$ 1.33
– DILUTED	$ 0.39	$ 0.32	$ 0.28	$ 0.27	$ 1.27
NET INCOME	$ 31,817	$ 64,686	$ 10,498	$ 11,880	$ 118,880
PER SHARE – BASIC	$ 0.27	$ 0.56	$ 0.09	$ 0.10	$ 1.02
– DILUTED	$ 0.26	$ 0.53	$ 0.08	$ 0.10	$ 0.97

(1) Restated for inclusion of Mazeppa Processing Partnership.

(2) Restated to exclude transportation and realized hedging gains and losses.

(3) Restated to exclude realized hedge gains and losses.

Production in the third quarter of 2003 was unusually low due to the shut-in of the Mazeppa gas plant for turnaround in September 2003. Third quarter revenue also declined as a result of the turnaround.

An unrealized foreign exchange gain on the translation of the Company's U.S. denominated debt in the first and second quarters of 2003 and a recovery of future income taxes in the second quarter, due to a reduction in federal and provincial income tax rates on income earned from resource activities, significantly increased quarterly net income in the first half of the year.

FOURTH QUARTER 2004

Average fourth quarter 2004 production increased 3% from the third quarter of 2004. Production in December 2004 reached approximately 30,000 boe/d, before the disposition of 600 boe/d of production at year end.

Total revenue in the fourth quarter decreased slightly due to lower realized prices, despite higher production than in the third quarter. After the elimination of non-operational items, net income in the fourth quarter was lower than in the prior quarter due to lower realized prices, additional interest expense and depreciation and depletion charges.

Selected Annual Information

YEARS ENDED DECEMBER 31, ($000s)	**2004**	2003	2002
TOTAL REVENUE	**$ 391,659**	$ 346,565	$ 226,597
NET INCOME	**$ 63,633**	$ 118,880	$ 18,312
PER SHARE – BASIC	**$ 0.54**	$ 1.02	$ 0.16
– DILUTED	**$ 0.51**	$ 0.97	$ 0.16
TOTAL ASSETS	**$ 1,330,611**	$ 1,064,320	$ 823,859
TOTAL LONG-TERM FINANCIAL LIABILITIES	**$ 198,594**	$ 213,246	$ 260,634

Total revenue in 2004 was higher than in the two previous years due to a combination of increased production and higher prices.

Net income in 2004 decreased from the prior year as 2003 was impacted by a $39 million after tax unrealized foreign exchange gain on the Company's U.S. dollar denominated debt and a $37 million recovery of future income taxes relating to statutory income tax rate changes. Net income in 2002 was lower due to significantly lower realized prices and decreased production levels.

Total assets were $1.3 billion at December 31, 2004, an increase of 25% from the prior year due to capital expenditures of $316 million. Capital expenditures of $221 million in 2003 increased total assets by 29% from 2002.

The change in long-term financial liabilities results from an unrealized gain due to the translation of the Company's U.S. $165 million senior term notes. The principal of the senior term notes remains fixed at U.S.$165 million while the value of the notes shown on the consolidated balance sheets varies in response to movement in the Canadian/U.S. exchange rate.

Trading and Share Statistics

As at March 15, 2005 there were 124,961,986 common shares outstanding, including the 7.5 million common share issued on February 18, 2005, and 12,522,717 stock options outstanding.

	2004	2003	2002
AVERAGE DAILY TRADING VOLUME *(000s)*	**674,764**	686,100	324,865
SHARE PRICE *($/share)*			
HIGH	**$ 11.43**	$ 6.35	$ 5.35
LOW	**$ 5.89**	$ 4.40	$ 3.20
CLOSE	**$ 10.85**	$ 6.00	$ 5.09
MARKET CAPITALIZATION AT DECEMBER 31 *($000s)*	**$ 1,273,282**	$ 698,535	$ 591,819
SHARES OUTSTANDING *(000s)*	**117,354**	116,423	116,271

Further Information

Additional information about Compton, including the Company's Annual Information Form, is available on the Canadian Securities Administrators' System for Electronic Document Analysis and Retrieval ("SEDAR") at www.sedar.com.

Management's Report

To the Shareholders of Compton Petroleum Corporation

The accompanying consolidated financial statements of Compton Petroleum Corporation and all other financial and operating information contained in this Annual Report are the responsibility of Management. The consolidated financial statements have been prepared in accordance with accounting policies detailed in the notes to the consolidated financial statements and in accordance with generally accepted accounting principles in Canada.

The Company's systems of internal control have been designed and maintained to provide reasonable assurance that assets are properly safeguarded and that the financial records are sufficiently well maintained to provide relevant, timely and reliable information to management.

External auditors, appointed by the shareholders, have independently examined the consolidated financial statements. They have performed such tests as they deemed necessary to enable them to express an opinion on these consolidated financial statements.

The Audit, Finance and Risk Committee of the Board of Directors has reviewed these consolidated financial statements with management and the external auditors. The Board of Directors has approved the consolidated financial statements on the recommendation of the Audit, Finance and Risk Committee.

E.G. Sapieha, C.A.
President &
Chief Executive Officer

N.G. Knecht, C.A.
Vice President Finance &
Chief Financial Officer

March 15, 2005

Independent Auditors' Report

To the Shareholders of Compton Petroleum Corporation

We have audited the consolidated balance sheets of Compton Petroleum Corporation as at December 31, 2004 and 2003 and the consolidated statements of earnings, retained earnings and cash flow for each of the years in the three year period ended December 31, 2004. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in Canada and the standards of the Public Company Accounting Oversight Board (United States). These standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2004 and 2003 and the results of its operations and cash flow for each of the years in the three year period ended December 31, 2004 in accordance with accounting principles generally accepted in Canada.

Grant Thornton LLP

Grant Thornton LLP
Chartered Accountants
Calgary, Alberta, Canada
March 15, 2005

Comments by Auditor for U.S. Readers on Canada-U.S. Reporting Differences

The standards of the Public Company Accounting Oversight Board (United States) require the addition of an explanatory paragraph (following the opinion paragraph) when there is a change in accounting principles that has a material effect on the comparability of the Company's financial statements, such as the change described in Note 2 to the consolidated financial statements. Also, in the United States of America, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is a restatement of the Company's historical financial statements, such as correction of an error in application of accounting principle described in Note 18(f) to the consolidated financial statements. Our report to the shareholders dated March 15, 2005 is expressed in accordance with Canadian reporting standards, which do not require a reference to such a change in accounting principles in the Auditors' Report, when the change is properly accounted for and adequately disclosed in the consolidated financial statements.

Grant Thornton LLP

Grant Thornton LLP
Chartered Accountants
Calgary, Alberta, Canada
March 15, 2005

CONSOLIDATED BALANCE SHEETS

AS AT DECEMBER 31, (thousands of dollars)		2004	2003
ASSETS			
CURRENT			
CASH		**$ 10,068**	$ 15,548
ACCOUNTS RECEIVABLE AND OTHER		**115,113**	94,937
UNREALIZED HEDGE GAIN	*NOTE 15(a)(i)*	**1,985**	–
		127,166	110,485
PROPERTY AND EQUIPMENT	*NOTE 5*	**1,178,550**	942,303
GOODWILL	*NOTE 3*	**7,914**	–
DEFERRED FINANCING CHARGES AND OTHER		**9,729**	11,532
DEFERRED RISK MANAGEMENT LOSS	*NOTE 15(a)(ii)*	**7,252**	–
		$ 1,330,611	$ 1,064,320
LIABILITIES			
CURRENT			
BANK DEBT	*NOTE 6*	**$ 220,000**	$ 164,500
ACCOUNTS PAYABLE		**125,483**	85,885
INCOME TAXES PAYABLE		**301**	2,757
		345,784	253,142
SENIOR TERM NOTES	*NOTE 7*	**198,594**	213,246
ASSET RETIREMENT OBLIGATIONS	*NOTE 9*	**18,006**	17,329
UNREALIZED HEDGE LIABILITY	*NOTE 15(a)(iii)*	**11,416**	–
FUTURE INCOME TAXES	*NOTE 14(b)*	**261,196**	223,807
NON-CONTROLLING INTEREST	*NOTE 4*	**71,537**	(110)
		906,533	707,414
SHAREHOLDERS' EQUITY			
CAPITAL STOCK	*NOTE 10(b)*	**135,526**	131,577
CONTRIBUTED SURPLUS	*NOTE 11(c)*	**3,840**	760
RETAINED EARNINGS		**284,712**	224,569
		424,078	356,906
		$ 1,330,611	$ 1,064,320
COMMITMENTS AND CONTINGENT LIABILITIES	*NOTE 17*		

ON BEHALF OF THE BOARD

M.F. Belich

Director

J.A. Thomson

Director

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF EARNINGS

YEARS ENDED DECEMBER 31, (thousands of dollars, except per share data)		**2004**	2003	2002
REVENUE				
OIL AND NATURAL GAS REVENUES		**$ 391,659**	$ 346,565	$ 226,597
ROYALTIES		**(93,416)**	(82,566)	(47,497)
		298,243	263,999	179,100
EXPENSES				
OPERATING		**55,655**	49,916	45,546
TRANSPORTATION		**8,595**	8,447	8,167
GENERAL AND ADMINISTRATIVE		**15,215**	12,206	9,845
INTEREST AND FINANCE CHARGES	*NOTE 8*	**33,733**	30,595	23,197
DEPLETION AND DEPRECIATION		**82,554**	61,749	55,473
FOREIGN EXCHANGE (GAIN) LOSS	*NOTE 7*	**(14,631)**	(47,368)	1,583
ACCRETION OF ASSET RETIREMENT OBLIGATIONS	*NOTE 9*	**1,670**	1,436	1,241
STOCK-BASED COMPENSATION	*NOTE 11(c)(d)*	**3,410**	793	190
RISK MANAGEMENT LOSS (GAIN)	*NOTE 15(a)(iv)*	**8,808**	4,132	(4,424)
		195,009	121,906	140,818
EARNINGS BEFORE TAXES AND NON-CONTROLLING INTEREST		**103,234**	142,093	38,282
INCOME TAXES	*NOTE 14(a)*			
CURRENT		**2,751**	3,282	1,428
FUTURE		**33,432**	20,041	18,542
		36,183	23,323	19,970
EARNINGS BEFORE NON-CONTROLLING INTEREST		**67,051**	118,770	18,312
NON-CONTROLLING INTEREST	*NOTE 4*	**3,418**	(110)	–
NET EARNINGS		**$ 63,633**	$ 118,880	$ 18,312
NET EARNINGS PER SHARE	*NOTE 12*			
BASIC		**$ 0.54**	$ 1.02	$ 0.16
DILUTED		**$ 0.51**	$ 0.97	$ 0.16

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

YEARS ENDED DECEMBER 31, (thousands of dollars)		**2004**	2003	2002
RETAINED EARNINGS, BEGINNING OF YEAR		**$ 224,569**	$ 112,039	$ 96,093
NET EARNINGS		**63,633**	118,880	18,312
PREMIUM ON REDEMPTION OF SHARES	*NOTE 10(b)*	**(3,490)**	(6,350)	(2,366)
RETAINED EARNINGS, END OF YEAR		**$ 284,712**	$ 224,569	$ 112,039

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOW

YEARS ENDED DECEMBER 31, (thousands of dollars)		**2004**	2003	2002
OPERATING ACTIVITIES				
NET EARNINGS		**$ 63,633**	$ 118,880	$ 18,312
AMORTIZATION OF DEFERRED CHARGES AND OTHER		**2,101**	2,208	1,367
DEPLETION AND DEPRECIATION		**82,554**	61,749	55,473
ACCRETION OF ASSET RETIREMENT OBLIGATIONS		**1,670**	1,436	1,241
UNREALIZED FOREIGN EXCHANGE (GAIN) LOSS		**(14,652)**	(47,388)	1,583
FUTURE INCOME TAXES		**33,432**	20,041	18,542
UNREALIZED RISK MANAGEMENT LOSS	*NOTE 15(a)(iv)*	**2,179**	–	–
STOCK-BASED COMPENSATION		**3,410**	760	–
ASSET RETIREMENT EXPENDITURES		**(614)**	(2,683)	(446)
NON-CONTROLLING INTEREST		**3,418**	(110)	–
CASH FLOW FROM OPERATIONS		**177,131**	154,893	96,072
CHANGE IN NON-CASH WORKING CAPITAL	*NOTE 16*	**(12,594)**	1,318	(5,166)
		164,537	156,211	90,906
FINANCING ACTIVITIES				
ISSUANCE (REPAYMENT) OF BANK DEBT		**43,373**	124,500	(190,000)
ISSUANCE OF SENIOR NOTES		**–**	–	259,050
DEFERRED FINANCING CHARGES		**–**	(128)	(14,810)
PROCEEDS FROM SHARE ISSUANCES, NET		**3,258**	6,400	18,177
PROCEEDS FROM PARTNERSHIP UNIT ISSUANCE		**74,343**	–	–
DISTRIBUTIONS TO PARTNER		**(6,114)**	–	–
REDEMPTION OF COMMON SHARES		**(4,005)**	(7,942)	(3,026)
CHANGE IN NON-CASH WORKING CAPITAL	*NOTE 16*	**324**	(1,387)	3,514
		111,179	121,443	72,905
INVESTING ACTIVITIES				
PROPERTY AND EQUIPMENT ADDITIONS		**(296,676)**	(222,055)	(127,993)
CORPORATE ACQUISITIONS	*NOTE 3*	**(12,132)**	–	–
PROPERTY ACQUISITIONS		**(20,830)**	(65,622)	(44,857)
PROPERTY DISPOSITIONS		**19,276**	2,194	17,700
CHANGE IN NON-CASH WORKING CAPITAL	*NOTE 16*	**29,166**	8,652	1,012
		(281,196)	(276,831)	(154,138)
CHANGE IN CASH		**(5,480)**	823	9,673
CASH, BEGINNING OF YEAR		**15,548**	14,725	5,052
CASH, END OF YEAR		**$ 10,068**	$ 15,548	$ 14,725

See accompanying notes to the consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2004 (Tabular amounts in thousands of dollars, unless otherwise stated)

1. Significant Accounting Policies

Compton Petroleum Corporation (the "Company" or "Compton") is in the business of the exploration for and production of petroleum and natural gas reserves in the Western Canadian Sedimentary Basin.

a) Basis of presentation

The consolidated financial statements of the Company have been prepared in accordance with accounting principles generally accepted in Canada within the framework of the accounting policies summarized below. Information prepared in accordance with accounting principles generally accepted in the United States is included in Note 18.

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries from their respective dates of acquisition. The consolidated financial statements also include the accounts of Mazeppa Processing Partnership in accordance with Accounting Guideline 15 ("AcG-15") Consolidation of Variable Interest Entities, as outlined in Note 4.

All amounts are presented in Canadian dollars unless otherwise stated.

b) Measurement uncertainty

The timely preparation of financial statements requires that Management make estimates and assumptions and use judgment regarding assets, liabilities, revenues and expenses. Such estimates relate primarily to transactions and events that have not settled as of the date of the financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

Amounts recorded for depletion and depreciation, asset retirement obligations and amounts used in impairment test calculations are based upon estimates of petroleum and natural gas reserves and future costs to develop those reserves. By their nature, these estimates of reserves, costs and related future cash flows are subject to uncertainty, and the impact on the consolidated financial statements of future periods could be material.

c) Property and equipment

I) CAPITALIZED COSTS

The Company follows the full cost method of accounting for its petroleum and natural gas operations as determined by the Canadian Institute of Chartered Accounts ("CICA"), Accounting Guideline 16 ("AcG-16"). Under this method all costs related to the exploration for and development of petroleum and natural gas reserves are capitalized. Costs include lease acquisition costs, geological and geophysical expenses, costs of drilling both producing and non-producing wells, production facilities, asset retirement costs and certain general and administrative expenses directly related to exploration and development activities.

Proceeds from the sale of properties are applied against capitalized costs, without any gain or loss being realized, unless such sale would significantly alter the rate of depletion and depreciation.

Expenditures related to renewals or betterments that improve the productive capacity or extend the life of an asset are capitalized. Maintenance and repairs are expensed as incurred.

1. Significant Accounting Policies *(Continued)*

II) DEPLETION AND DEPRECIATION

Depletion and depreciation of property and equipment is provided using the unit-of-production method based upon estimated proved petroleum and natural gas reserves. The costs of significant undeveloped properties are excluded from costs subject to depletion until it is determined whether or not proved reserves are attributable to the properties or impairment has occurred. Estimated future costs to be incurred in developing proved reserves are included in costs subject to depletion. For depletion and depreciation purposes, relative volumes of natural gas production and reserves are converted at the energy equivalent conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil.

Depreciation of certain midstream facilities is provided for on a straight line basis over 30 years and depreciation of office equipment is provided for on a declining balance basis at 20% per annum.

III) IMPAIRMENT TEST

At each reporting period the Company performs an impairment test to determine the recoverability of capitalized costs associated with reserves. An impairment loss is recognized when the carrying amount of a cost centre exceeds its fair value. The carrying amount of the cost centre is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from proved reserves plus the costs of unproved properties. If the sum of the cash flows is less than the carrying amount, the impairment loss is limited to the amount by which the carrying amount exceeds the sum of the fair value of proved and probable reserves and the costs of unproved properties that have been subject to a separate impairment test and contain no probable reserves.

IV) ASSET RETIREMENT OBLIGATIONS

The Company recognizes the fair value of estimated asset retirement obligations on the consolidated balance sheet when a reasonable estimate of fair value can be made. Asset retirement obligations include those legal obligations where the Company will be required to retire tangible long lived assets such as well sites, pipelines and facilities. The asset retirement cost, equal to the initially estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long lived asset. Changes in the estimated obligation resulting from revisions to estimated timing or amount of undiscounted cash flows are recognized as a change in the asset retirement obligation and the related asset retirement cost.

Asset retirement costs are amortized using the unit-of-production method and are included in depletion and depreciation in the consolidated statement of earnings. Increases in the asset retirement obligations resulting from the passage of time are recorded as accretion of asset retirement obligations in the consolidated statement of earnings.

V) INVENTORIES

Physical inventory held for exploration, development and operating activities is included in property and equipment and is valued at cost.

d) Goodwill

Goodwill is recorded on a corporate acquisition when the purchase price is in excess of the fair values assigned to assets acquired and liabilities assumed. Goodwill is not amortized and an impairment test is performed at least annually to evaluate the carrying value. To assess impairment, the fair value of the reporting unit is determined and compared to the carrying value. If fair value is less than the carrying value then a second test is performed to determine the amount of the impairment. Any loss recognized is equal to the difference between the implied fair value and the carrying value of the goodwill.

1. Significant Accounting Policies *(Continued)*

e) Financial instruments

Financial instruments consist mainly of accounts receivable and other, accounts payable and long-term debt. There are no significant differences between the carrying value of these financial instruments and their estimated fair value, except as disclosed in Note 15(b)(ii).

The Company uses financial instruments for non-trading purposes to manage fluctuations in commodity prices, foreign currency exchange rates and interest rates, as described in Note 15. The Company has elected not to designate any of its current risk management activities as accounting hedges and accounts for all derivative financial instruments using the mark-to-market accounting method.

f) Joint operations

Certain petroleum and natural gas activities are conducted jointly with others. These consolidated financial statements reflect only the Company's proportionate interest in such activities.

g) Flow-through shares

Resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow-through share arrangements are renounced to investors in accordance with income tax legislation. The liability for future income taxes is increased and capital stock is reduced by the estimated tax benefits transferred to shareholders at the time the resource expenditure deductions are renounced.

h) Earnings per share amounts

The Company uses the treasury stock method to determine the dilutive effect of stock options. This method assumes that proceeds received from the exercise of in-the-money stock options are used to repurchase common shares at the average market price for the period. Basic net earnings per common share are determined by dividing net earnings by the weighted average number of common shares outstanding during the period. Diluted earnings per share are computed by giving effect to the potential dilution that would occur if stock options were exercised.

i) Income taxes

Income taxes are recorded using the liability method of accounting. Future income taxes are calculated based on the difference between the accounting and income tax basis of an asset or liability, using the substantively enacted income tax rates. Changes in income tax rates that are substantively enacted are reflected in the accumulated future income tax balances in the period the change occurs.

j) Revenue recognition

Revenue associated with the production and sale of crude oil, natural gas and natural gas liquids owned by the Company is recognized when the purchaser takes possession of the commodity product. Other revenue is recognized in the period that the service is provided to the customer.

k) Stock-based compensation plan

The Company has stock-based compensation plans which include stock options and an employee stock savings plan.

The Company records compensation expense in the consolidated statements of earnings for stock options granted to Directors, Officers and employees using the fair-value method. Compensation costs are recognized over the vesting period. Fair values are determined using the Black-Scholes option pricing model.

The Company matches employee contributions to the stock savings plan and these cash payments are recorded as compensation expense as incurred.

1. Significant Accounting Policies *(Continued)*

l) Deferred financing charges

Financing costs related to the issuance of the senior term notes have been deferred and are amortized over the term of the notes on a straight line basis.

m) Foreign currency translation

Long-term debt payable in U.S. dollars is translated into Canadian dollars at the period end exchange rate, with any resulting adjustment recorded in the consolidated statement of earnings.

n) Dividend policy

The Company has neither declared nor paid any dividends on its common shares. The Company intends to retain its earnings to finance growth and expand its operations and does not anticipate paying any dividends on its common shares in the foreseeable future.

o) Defined benefit pension plan

The Company accrues for obligations under a defined benefit pension plan and the related costs, net of plan assets. The cost of the pension is actuarially determined using the projected benefit method based on length of service and reflects Management's best estimate of expected plan investment performance, salary escalation and retirement age of employees.

p) Reclassification

Certain information provided for prior years has been reclassified to conform with the current period presentation.

2. Changes in Accounting Policy

Hedging relationships

On January 1, 2004, the Company adopted the amendments made to the CICA modified Accounting Guideline 13 ("AcG-13") "Hedging Relationships" and Emerging Issues Committee Abstract 128 ("EIC 128"), "Accounting for Trading, Speculative or Non Trading Derivative Financial Instruments". Derivative instruments that do not qualify for hedge accounting or are not designated as hedges, are recorded on the balance sheet as either an asset or liability with changes in fair value recognized in earnings.

The Company has elected not to designate any of its risk management activities in place at December 31, 2003 as accounting hedges under AcG-13 and accordingly, accounts for all derivative financial instruments using the mark-to-market method. The impact on the Company's consolidated financial statements at January 1, 2004 was the recognition of an unrealized hedge liability of $10.9 million and a deferred risk management loss of $10.9 million, before tax. The deferred risk management loss is charged to earnings as the contracts are settled and the liability is re-valued at each balance sheet date, with any gain or loss recognized in earnings.

3. Business Combinations

On April 12, 2004 and November 15, 2004 respectively, the Company acquired 100% of the issued and outstanding shares of Redwood Energy, Ltd. and Mayfair Energy Ltd. for total cash consideration of $12.1 million plus the assumption of $12.1 million of debt. Both were independent exploration and production companies with operations in the Company's core areas.

The business combinations have been accounted for using the purchase method with results of operations included in the consolidated financial statements from the date of acquisition. Goodwill recognized on these transactions amounted to $7.9 million.

During the year, both companies were wound up into Compton Petroleum Corporation and dissolved.

4. Non-Controlling Interest

Mazeppa Processing Partnership ("MPP" or "the Partnership") is a limited partnership organized under the laws of the province of Alberta and owns certain midstream facilities, including gas plants and pipelines in Southern Alberta. The Company processes a significant portion of its production from the area through these facilities pursuant to a processing agreement with MPP. The Company does not have an ownership position in MPP, however, the Company, through a management agreement, manages the activities of MPP and is considered to be the primary beneficiary of MPP's operations. Pursuant to AcG-15, these consolidated financial statements include the assets, liabilities and operations of the Partnership. Equity in the Partnership, attributable to the partners of MPP, is recorded on consolidation as a non-controlling interest and is comprised of the following:

AS AT DECEMBER 31	**2004**	2003
NON-CONTROLLING INTEREST, BEGINNING OF YEAR	**$ (110)**	$ –
PROCEEDS FROM ISSUE OF PARTNERSHIP UNITS, NET	**74,343**	–
EARNINGS (LOSS) ATTRIBUTABLE TO NON-CONTROLLING INTEREST	**3,418**	(110)
DISTRIBUTIONS TO LIMITED PARTNER	**(6,114)**	–
NON-CONTROLLING INTEREST, END OF YEAR	**$ 71,537**	$ (110)

Commencing May 1, 2004, pursuant to the terms of a processing agreement between Compton and MPP, Compton pays a monthly fee to MPP for the transportation and processing of natural gas through the MPP owned facilities. The fee is comprised of a fixed base fee of $764 thousand per month plus MPP operating costs, net of third party revenues. These amounts are eliminated from revenues and expenses on consolidation.

The processing agreement has a five year term ending April 1, 2009, at which time Compton may renew the agreement under terms determined at that time or purchase the Partnership units for the predetermined amount of $55 million, deemed to be fair value. In the event that the Company does not renew the processing agreement nor exercise the purchase option, the Limited Partner may dispose of the Partnership units to an independent third party.

MPP has guaranteed payment of certain obligations of its limited partner under a credit agreement between the limited partner and a syndicate of lenders. The maximum liability of the Partnership under the guarantee is limited to amounts due and payable to MPP by the Company pursuant to the processing agreement. The maximum liability at December 31, 2004 is $39.7 million, payable over the remaining term of the processing agreement. The Company has determined that its exposure to loss under these arrangements is minimal, if any.

5. Property and Equipment

	2004			2003		
AS AT DECEMBER 31,	**COST**	**ACCUMULATED DEPLETION AND DEPRECIATION**	**NET**	COST	ACCUMULATED DEPLETION AND DEPRECIATION	NET
EXPLORATION AND DEVELOPMENT COSTS	**$ 1,161,396**	**$ (281,614)**	**$ 879,782**	$ 931,970	$ (212,223)	$ 719,747
PRODUCTION EQUIPMENT AND PROCESSING FACILITIES	**317,477**	**(34,150)**	**283,327**	231,918	(21,411)	210,507
INVENTORY	**6,187**	**–**	**6,187**	2,246	–	2,246
FUTURE ASSET RETIREMENT COSTS	**9,576**	**(3,111)**	**6,465**	10,557	(3,422)	7,135
OFFICE EQUIPMENT	**6,005**	**(3,216)**	**2,789**	5,143	(2,475)	2,668
	$ 1,500,641	**$ (322,091)**	**$ 1,178,550**	$ 1,181,834	$ (239,531)	$ 942,303

5. Property and Equipment *(Continued)*

Employee salaries and insurance costs of $4.6 million (2003 - $4.0 million) directly related to exploration and development activities are capitalized. No other general and administrative costs are capitalized.

Future capital expenditures of $89.1 million (2003 - $62.4 million; 2002 - $37.5 million), as estimated by independent engineers, relating to the development of proved reserves have been included in costs subject to depletion. Undeveloped properties with a cost at December 31, 2004 of $187.8 million (2003 - $161.9 million; 2002 - $155.0 million) included in exploration and development costs, have not been subject to depletion.

The prices used in the impairment test evaluation of the Company's natural gas, crude oil and natural gas liquids reserves were:

	NATURAL GAS	OIL	NGL
AS AT DECEMBER 31, 2004	$ PER MCF	$ PER BBL	$ PER BBL
2005	$ 7.03	$ 46.13	$ 42.67
2006	$ 6.77	$ 43.75	$ 40.28
2007	$ 6.57	$ 40.60	$ 36.64
2008	$ 6.24	$ 38.05	$ 34.14
2009	$ 6.04	$ 36.33	$ 32.52
APPROXIMATE % INCREASE THEREAFTER	1.5	1.5	1.5

6. Credit Facilities

AS AT DECEMBER 31	**2004**	2003
AUTHORIZED	**$ 240,000**	$ 185,000
PRIME RATE	**3,000**	21,000
BANKERS' ACCEPTANCE	**217,000**	143,500
UTILIZED	**$ 220,000**	$ 164,500

As of December 31, 2004, the Company had arranged authorized senior credit facilities with a syndicate of Canadian banks in the amount of $240 million. Advances under the facilities can be drawn and currently bear interest as follows:

Prime rate plus 0.45%

Bankers' Acceptance rate plus 1.45%

LIBOR rate plus 1.45%

Margins are determined based on the ratio of total consolidated debt to consolidated cash flow. These facilities mature on July 7, 2005.

The senior credit facilities are secured by a first fixed and floating charge debenture in the amount of $325.0 million covering all the Company's assets and undertakings.

7. Senior Term Notes

AS AT DECEMBER 31	**2004**	2003
SENIOR TERM NOTES (U.S. $165.0 MILLION)		
PROCEEDS ON ISSUANCE	**$ 259,051**	$ 259,051
CUMULATIVE UNREALIZED FOREIGN EXCHANGE GAIN	**(60,457)**	(45,805)
	$ 198,594	$ 213,246

7. Senior Term Notes *(Continued)*

The senior term notes bear interest at 9.90%, semi-annual, with principal repayable on May 15, 2009 and are subordinate to the Company's bank credit facilities.

The notes are not redeemable prior to May 15, 2006, except in limited circumstances. After that time, they can be redeemed in whole or part, at the rates indicated below:

May 15, 2006	104.950%
May 15, 2007	102.475%
May 15, 2008 and thereafter	100.000%

The Company entered into a cross currency, interest rate swap arrangement with its banking syndicate whereby interest paid by the Company on the U.S. $165.0 million principal amount is based upon the 90 day Bankers' Acceptance rate plus 4.85%, calculated on the $259.0 million proceeds of issuance. This arrangement resulted in an effective interest rate of 7.24% during year ended December 31, 2004 (2003 - 7.85%) net of gains realized on the swap arrangements, see Note 15(a)(iv).

The unrealized foreign exchange gain recognized in 2004 was $14.7 million (2003 – $47.4 million) and the accumulated unrealized gain to December 31, 2004 is $60.5 million.

8. Interest and Finance Charges

Amounts charged to expense during the years ended are as follows:

YEARS ENDED DECEMBER 31,	**2004**	2003	2002
INTEREST ON BANK DEBT, NET	**$ 9,662**	$ 6,611	$ 5,339
INTEREST ON SENIOR TERM NOTES	**21,281**	21,711	15,932
FINANCE CHARGES	**2,790**	2,273	1,926
TOTAL	**$ 33,733**	$ 30,595	$ 23,197

Finance charges include the amortization of deferred changes and current year expenses.

9. Asset Retirement Obligations

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the obligations associated with the retirement of oil and natural gas assets:

AS AT DECEMBER 31,	**2004**	2003
ASSET RETIREMENT OBLIGATIONS, BEGINNING OF YEAR	**$ 17,329**	$ 17,335
LIABILITIES INCURRED	**3,357**	1,241
LIABILITIES SETTLED AND DISPOSED	**(4,350)**	(2,683)
ACCRETION EXPENSE	**1,670**	1,436
ASSET RETIREMENT OBLIGATIONS, END OF YEAR	**$ 18,006**	$ 17,329

The total undiscounted amount of estimated cash flows required to settle the obligations is $148.9 million (2003 - $135.1 million), which has been discounted using a credit adjusted risk free rate of 10.8%. The majority of these obligations are not expected to be settled for several years or decades into the future. Settlements will be funded from general Company resources at the time of retirement and removal.

10. Capital Stock

a) Authorized

The Company is authorized to issue an unlimited number of common shares and an unlimited number of preferred shares, issuable in series.

b) Issued and outstanding

AS AT DECEMBER 31,	2004 NUMBER OF SHARES (000s)	2004 AMOUNT	2003 NUMBER OF SHARES (000s)	2003 AMOUNT
COMMON SHARES OUTSTANDING, BEGINNING OF YEAR	**116,423**	**$ 131,577**	116,271	$ 128,079
SHARES ISSUED FOR CASH, NET	**–**	**–**	587	2,712
SHARES ISSUED FOR PROPERTY	**110**	**875**	15	81
SHARES ISSUED UNDER STOCK OPTION PLAN	**1,271**	**3,589**	913	2,296
SHARES REPURCHASED	**(450)**	**(515)**	(1,363)	(1,591)
COMMON SHARES OUTSTANDING, END OF YEAR	**117,354**	**$ 135,526**	116,423	$ 131,577

Effective March 10, 2004, the Company received approval from the Toronto Stock Exchange for a Normal Course Issuer Bid (the "Bid"). Under the Bid, the Company could purchase for cancellation up to 5,800,000 of its common shares, representing 4.95% of the 117,242,073 common shares outstanding as of February 29, 2004. The Bid expired on March 9, 2005 and was subsequently renewed.

During the year, the Company purchased for cancellation 450,100 common shares at an average price of $8.90 per share (2003 - 1,363,400 shares at an average price of $5.83 per share) pursuant to a normal course issuer bid. The excess of the purchase price over book value has been charged to retained earnings.

In February 2005, the Company issued 7,500,000 common shares in the capital of the Company for gross proceeds of $90.0 million before underwriters' fees of $3.6 million and expenses of issue estimated to be $0.4 million. The net proceeds of this offering were initially used to repay a portion of the current indebtedness of the Company under the credit facilities and thereafter, to expand and accelerate the Company's capital expenditure program.

c) Shareholder rights plan

The Company has a shareholder rights plan (the "Plan") to ensure all shareholders are treated fairly in the event of a take-over offer or other acquisition of control of the Company.

Pursuant to the Plan, the Board of Directors authorized and declared the distribution of one Right in respect of each common share outstanding. In the event that an acquisition of 20% or more of the Company's shares is completed and the acquisition is not a permitted bid, as defined by the Plan, each Right will permit the holder to acquire common shares at a 50% discount to the market price at that time.

11. Stock-Based Compensation Plans

a) Stock option plan

The Company has implemented a stock option plan for Directors, Officers and employees. The exercise price of each option approximates the market price for the common shares on the date the option was granted. Options granted under the plan before June 1, 2003 are generally fully exercisable after four years and expire ten years after the grant date. Options granted under the plan after June 1, 2003 are generally fully exercisable after four years and expire five years after the grant date.

11. Stock-Based Compensation Plans *(Continued)*

The following tables summarize the information relating to stock options:

	2004		2003	
AS AT DECEMBER 31,	**STOCK OPTIONS (000s)**	**WEIGHTED AVERAGE EXERCISE PRICE**	STOCK OPTIONS (000s)	WEIGHTED AVERAGE EXERCISE PRICE
OUTSTANDING, BEGINNING OF YEAR	**10,672**	**$ 2.54**	10,357	$ 2.21
GRANTED	**2,549**	**$ 7.34**	1,503	$ 5.18
EXERCISED	**(1,271)**	**$ 2.56**	(913)	$ 2.52
CANCELLED	**(295)**	**$ 5.26**	(275)	$ 4.63
OUTSTANDING, END OF YEAR	**11,655**	**$ 3.51**	10,672	$ 2.54
EXERCISABLE, END OF YEAR	**7,812**	**$ 2.19**	7,763	$ 1.77

The range of exercise prices of stock options outstanding and exercisable at December 31, 2004 are as follows:

	OUTSTANDING OPTIONS			EXERCISABLE OPTIONS	
RANGE OF EXERCISE PRICES	NUMBER OF OPTIONS OUTSTANDING (000s)	AVERAGE REMAINING CONTRACTUAL LIFE (YEARS)	WEIGHTED AVERAGE EXERCISE PRICE	NUMBER OF OPTIONS OUTSTANDING (000s)	WEIGHTED AVERAGE EXERCISE PRICE
$0.60 - $0.99	2,875	1.8	$ 0.64	2,875	$ 0.64
$1.00 - $2.99	2,168	4.1	1.73	2,166	1.73
$3.00 - $3.99	1,702	6.3	3.43	1,279	3.32
$4.00 - $4.99	1,799	7.1	4.29	992	4.19
$5.00 - $6.99	1,335	4.0	5.86	392	5.89
$7.00 - $10.80	1,776	4.4	7.88	108	7.58
	11,655	4.3	$ 3.51	7,812	$ 2.19

b) Stock options granted prior to January 1, 2003

The Company has not recorded stock-based compensation expense in the consolidated statements of earnings related to stock options granted prior to 2003. If the Company had applied the fair value method to options granted prior to 2003, the Company's pro-forma net earnings and net earnings per share would have been as indicated below:

YEARS ENDED DECEMBER 31,	**2004**	2003	2002
NET EARNINGS			
AS REPORTED	**$ 63,633**	$ 118,880	$ 18,312
LESS FAIR VALUE OF STOCK OPTIONS	**(1,545)**	(2,317)	(3,317)
PRO-FORMA	**$ 62,088**	$ 116,563	$ 14,995
NET EARNINGS PER COMMON SHARE - BASIC			
AS REPORTED	**$ 0.54**	$ 1.02	$ 0.16
PRO-FORMA	**$ 0.53**	$ 1.00	$ 0.13
NET EARNINGS PER COMMON SHARE - DILUTED			
AS REPORTED	**$ 0.51**	$ 0.97	$ 0.16
PRO-FORMA	**$ 0.50**	$ 0.95	$ 0.13

11. Stock-Based Compensation Plans *(Continued)*

c) Stock options granted after January 1, 2003

The Company has recorded stock-based compensation expense in the consolidated statement of earnings for stock options granted to Directors, Officers and employees after January 1, 2003 using the fair value method.

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with weighted average assumptions for grants as follows:

YEARS ENDED DECEMBER 31,	**2004**	2003
WEIGHTED AVERAGE FAIR VALUE OF OPTIONS GRANTED	**$ 3.70**	$ 3.01
RISK FREE INTEREST RATE	**3.9%**	4.3%
EXPECTED LIVES *(years)*	**5.0**	6.1
EXPECTED VOLATILITY	**49.6%**	56.0%

The following table presents the reconciliation of contributed surplus with respect to stock-based compensation:

AS AT DECEMBER 31,	**2004**	2003
CONTRIBUTED SURPLUS, BEGINNING OF YEAR	**$ 760**	$ –
STOCK-BASED COMPENSATION EXPENSE	**3,410**	760
STOCK OPTIONS EXERCISED	**(330)**	–
CONTRIBUTED SURPLUS, END OF YEAR	**$ 3,840**	$ 760

d) Share appreciation rights plan

CICA Handbook section 3870 requires recognition of compensation costs with respect to changes in the intrinsic value for the variable component of fixed options. During the year ended December 31, 2004, there were no significant compensation costs related to the outstanding variable component of these share appreciation rights (2003 - $33,000; 2002 - $190,000). The liability related to the variable component of these options amounts to $1.7 million, which is included in accounts payable as at December 31, 2004 (2003 - $2.4 million). All outstanding options having a variable component expire at various times through 2011.

12. Per Share Amounts

The following table summarizes the common shares used in calculating net earnings per common share:

YEARS ENDED DECEMBER 31, (000s)	**2004**	2003	2002
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING - BASIC	**117,244**	116,267	113,428
EFFECT OF STOCK OPTIONS	**6,789**	5,856	4,572
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING - DILUTED	**124,033**	122,123	118,000

In calculating diluted earnings per common share for the year ended December 31, 2004, the Company excluded 288,000 options (2003 - 615,100; 2002 - 2,193,662), as the exercise price was greater than the average market price of its common shares in those years.

13. Defined Benefit Pension Plan

Substantially all of the employees of MPP are enrolled in a co-sponsored, defined benefit pension plan. The Company does not have a pension plan for other employees. Information relating to the MPP retirement plan is outlined below:

AS AT DECEMBER 31	**2004**	2003
ACCRUED BENEFIT OBLIGATION	**$ 5,855**	$ 5,331
FAIR VALUE OF PLAN ASSETS	**$ 5,221**	$ 4,488
FUNDED STATUS		
PLAN ASSETS LESS THAN BENEFIT OBLIGATION	**$ (634)**	$ (843)
UNAMORTIZED NET ACTUARIAL GAIN	**(269)**	(221)
UNAMORTIZED PAST SERVICE COSTS	**933**	1,000
ACCRUED BENEFIT (LIABILITY), INCLUDED IN DEFERRED FINANCING CHARGES AND OTHER	**$ 30**	$ (64)

Economic assumptions used to determine benefit obligation and periodic expense are:

YEARS ENDED DECEMBER 31	**2004**	2003
DISCOUNT RATE	**6.3%**	6.3%
EXPECTED RATE OF RETURN ON ASSETS	**7.0%**	7.0%
RATE OF COMPENSATION INCREASE	**4.5%**	4.0%
AVERAGE REMAINING SERVICE PERIOD OF COVERED EMPLOYEES	**15 YEARS**	15 YEARS

Actuarial evaluations are required every three years, the most recent being January 1, 2003.

Pension expense, included in MPP operating costs, is as follows:

YEARS ENDED DECEMBER 31	**2004**	2003
CURRENT SERVICE COST	**$ 190**	$ 111
INTEREST ON ACCRUED BENEFIT OBLIGATION	**336**	173
INTEREST ON ASSETS	**(333)**	(152)
AMORTIZATION OF PAST SERVICE COST	**67**	37
PENSION EXPENSE	**$ 260**	$ 169

MPP expects to contribute $354 thousand to the plan in 2005. Contributions by the participants to the pension plan were $66 thousand for the year ended December 31, 2004.

14. Income Taxes

a) The following table reconciles income taxes calculated at the Canadian statutory rate with actual income taxes:

YEARS ENDED DECEMBER 31,	**2004**	2003	2002
EARNINGS BEFORE TAXES	**$ 103,234**	$ 142,093	$ 38,282
CANADIAN STATUTORY RATE	**38.6%**	40.6%	42.1%
EXPECTED INCOME TAXES	**$ 39,848**	$ 57,690	$ 16,117
EFFECT ON TAXES RESULTING FROM			
NON-DEDUCTIBLE CROWN CHARGES	**17,611**	23,922	17,103
RESOURCE ALLOWANCE	**(13,535)**	(16,485)	(14,471)
FEDERAL CAPITAL TAX	**2,526**	2,497	1,428
STATUTORY TAX RATE REDUCTIONS	**(8,359)**	(37,130)	(1,340)
NON-TAXABLE PORTION OF FOREIGN EXCHANGE (GAIN) LOSS	**(2,831)**	(8,202)	334
OTHER	**923**	1,031	799
PROVISION FOR INCOME TAXES	**$ 36,183**	$ 23,323	$ 19,970
CURRENT			
INCOME TAXES	**$ 225**	$ 785	$ –
FEDERAL CAPITAL TAXES	**2,526**	2,497	1,428
FUTURE	**33,432**	20,041	18,542
	$ 36,183	$ 23,323	$ 19,970
EFFECTIVE TAX RATE	**35.0%**	16.4%	52.2%

A significant portion of the Company's taxable income is generated by a partnership. Income taxes are incurred on the partnership's taxable income in the year following its inclusion in the Company's consolidated net earnings. Current income tax will vary and is dependent upon the amount of capital expenditures incurred and the method of deployment.

In 2004, the Government of Alberta introduced legislation to reduce its corporate income tax rate from 12.5% to 11.5% and retain the resources allowance and non-deductible crown royalties regime until 2007.

b) The net future income tax liability is comprised of:

AS AT DECEMBER 31	**2004**	2003
FUTURE INCOME TAX LIABILITIES		
PROPERTY AND EQUIPMENT IN EXCESS OF TAX VALUES	**$ 199,931**	$ 169,855
TIMING OF PARTNERSHIP ITEMS	**67,089**	62,975
FOREIGN EXCHANGE GAIN ON LONG-TERM DEBT	**10,169**	7,934
FUTURE INCOME TAX ASSETS		
ATTRIBUTED CANADIAN ROYALTY INCOME	**(9,015)**	(9,667)
ASSET RETIREMENT OBLIGATIONS	**(6,057)**	(6,024)
NON-CAPITAL LOSSES CARRIED FORWARD	**(53)**	(789)
OTHER	**(868)**	(477)
NET FUTURE INCOME TAX LIABILITY	**$ 261,196**	$ 223,807

15. Financial Instruments

a) Derivative financial instruments and risk management activities

The Company is exposed to risks from fluctuations in commodity prices, interest rates and Canada/U.S. currency exchange rates. The Company utilizes various derivative financial instruments for non-trading purposes to manage and mitigate its exposure to these risks. As outlined in Note 2, effective January 1, 2004, the Company elected to account for all derivative financial instruments using the mark-to-market method.

Risk management activities during the year, utilizing derivative instruments, relate to commodity price hedges and cross currency interest rate swap arrangements and are summarized below:

i) COMMODITY PRICE HEDGES

The Company enters into hedge transactions relating to crude oil and natural gas prices to mitigate volatility in commodity prices. The contracts entered into are forward transactions providing the Company with a range of prices on the commodities sold. Outstanding hedge contracts at December 31, 2004 are:

COMMODITY	TERM	NOTIONAL VOLUME/DAY	PRICE COLLAR	MARK-TO-MARKET GAIN (LOSS)
NATURAL GAS	JAN. 1 - MAR. 31/05	23,810 MCF	\$7.51 - \$11.56/MCF	\$ 2,348
CRUDE OIL	JAN. 1 - DEC. 31/05	1,000 BBLS	U.S. \$35.00 - \$48.75/BBL	(363)
UNREALIZED HEDGE GAIN				\$ 1,985

The following table outlines the financial agreements entered into subsequent to December 31, 2004:

NATURAL GAS	APR. 1 - OCT. 31/05	14,286 MCF	\$6.21 - \$8.87/MCF
CRUDE OIL	FEB. 1 - DEC. 31/05	500 BBLS	U.S. \$43.00 - \$49.51/BBL

ii) DEFERRED RISK MANAGEMENT LOSS

At the beginning of the year, the Company elected not to designate any of its risk management activities as accounting hedges under Accounting Guideline 13 and accordingly accounts for all derivative instruments using the mark-to-market method. As a result, on January 1, 2004, the Company recorded a liability and a deferred risk management loss of \$10.9 million relating to then outstanding commodity hedges and the interest rate swap. During the year \$3.6 million of the deferred loss was charged to earnings. The remaining balance of \$7.3 million relates to the interest rate swap and will be charged to earnings in annual amounts of \$1.6 million until eliminated in 2009.

iii) CROSS CURRENCY INTEREST RATE SWAP

Concurrent with the closing of the senior notes offering, the Company entered into interest rate swap arrangements with its banking syndicate that convert fixed rate U.S. dollar denominated interest obligations into floating rate Canadian dollar denominated interest obligations. At December 31, 2004, the Company valued the liability relating to future unrealized losses on the swap arrangements to be \$11.4 million on a mark-to-market basis.

15. Financial Instruments *(Continued)*

IV) RISK MANAGEMENT LOSSES (GAINS)

Risk management gains and losses recognized during the year relating to the above are summarized below:

	COMMODITY CONTRACTS	INTEREST RATE SWAP	TOTAL
UNREALIZED			
AMORTIZATION OF DEFERRED LOSS	$ 2,001	$ 1,642	$ 3,643
CHANGE IN FAIR VALUE	(3,986)	2,522	(1,464)
	(1,985)	4,164	2,179
REALIZED			
CASH SETTLEMENTS	9,151	(2,522)	6,629
TOTAL	$ 7,166	$ 1,642	$ 8,808

Risk management losses (gains) of $4,132 and ($4,424) for 2003 and 2002 respectively reflect realized (gains) and losses recognized under hedge accounting.

b) Other financial instruments and risk

I) CREDIT RISK MANAGEMENT

Accounts receivable include amounts receivable for oil and natural gas sales which are generally made to large credit worthy purchasers and amounts receivable from joint venture partners which are recoverable from production. Accordingly, the Company views credit risks on these amounts as low.

The Company is exposed to losses in the event of non-performance by counter parties to financial instruments. The Company deals with major institutions and believes these risks are minimal.

II) FAIR VALUE OF FINANCIAL ASSETS AND LIABILITIES

Other than its senior term notes, the fair values of the Company's financial assets and liabilities that are included in the Company's consolidated balance sheet as at December 31, 2004, approximate their carrying value. The estimated fair value of senior term notes is $218.5 million as of December 31, 2004 (2003 - $231.6 million) based upon market information.

III) FOREIGN CURRENCY RISK MANAGEMENT

The Company is exposed to fluctuations in the exchange rate between the Canadian dollar and the U.S. dollar. Crude oil and to a certain extent natural gas prices are based upon reference prices denominated in U.S. dollars, while the majority of the Company's expenses are denominated in Canadian dollars. When appropriate, the Company enters into agreements to fix the exchange rate of Canadian dollars to U.S. dollars in order to manage the risk. During 2003, a gain of $2.5 million was realized and included in revenue (2002 - $0.4 million). At December 31, 2003, all swaps expired and the Company has not entered into any new arrangements.

16. Cash Flow

Changes in non-cash working capital items increased (decreased) cash as follows:

YEARS ENDED DECEMBER 31,	2004	2003	2002
ACCOUNTS RECEIVABLE AND OTHER	**$ (20,176)**	$ (16,593)	$ 1,312
ACCOUNTS PAYABLE	**39,598**	23,635	(2,608)
TAXES PAYABLE	**(2,526)**	1,541	656
	$ 16,896	$ 8,583	$ (640)
OPERATING ACTIVITIES			
ACCOUNTS RECEIVABLE AND OTHER	**$ (19,309)**	$ (3,675)	$ (6,480)
ACCOUNTS PAYABLE	**9,241**	3,452	658
TAXES PAYABLE	**(2,526)**	1,541	656
	(12,594)	1,318	(5,166)
FINANCING ACTIVITIES			
ACCOUNTS RECEIVABLE AND OTHER	**367**	(467)	–
ACCOUNTS PAYABLE	**(43)**	(920)	3,514
	324	(1,387)	3,514
INVESTING ACTIVITIES			
ACCOUNTS RECEIVABLE AND OTHER	**(1,233)**	(12,451)	7,792
ACCOUNTS PAYABLE	**30,399**	21,103	(6,780)
	29,166	8,652	1,012
	$ 16,896	$ 8,583	$ (640)

Amounts paid during the year relating to interest expense and capital taxes are as follows:

YEARS ENDED DECEMBER 31,	2004	2003	2002
INTEREST PAID	**$ 28,604**	$ 26,923	$ 15,042
CURRENT INCOME TAXES PAID	**$ 4,952**	$ 1,485	$ 1,084

17. Commitments and Contingent Liabilities

a) Commitments

The Company has committed to certain payments over the next five years, as follows:

	2005	2006	2007	2008	2009
OPERATING LEASES	$ 5,025	$ 10,985	$ 4,548	$ –	$ –
OFFICE RENT	1,268	1,356	249	–	–
MPP PARTNERSHIP DISTRIBUTIONS	9,172	9,172	9,172	9,172	3,057
SENIOR NOTES (U.S. $165 MILLION)	–	–	–	–	198,594
OTHER	136	243	–	–	–
	$ 15,601	$ 21,756	$ 13,969	$ 9,172	$ 201,651

b) Legal proceedings

The Company is involved in various legal claims associated with normal operations. These claims, although unresolved at the current time, in management's opinion, are minor in nature and are not expected to have a material impact on the financial position or results of operations of the Company.

18. United States accounting principles and reporting

Reconciliation of consolidated financial statements to United States generally accepted accounting principles

These consolidated financial statements have been prepared in accordance with accounting principles generally accepted in Canada ("Canadian GAAP") which, in most respects, conforms to accounting principles generally accepted in the United States of America ("U.S. GAAP"). The significant differences in those principles, as they apply to the Company's statements of earnings, balance sheets and statements of cash flows, are described below.

Reconciliation of Net Earnings under Canadian GAAP to U.S. GAAP:

FOR THE YEARS ENDED DECEMBER 31,	NOTE	**2004**	2003	2002
				(restated note F)
NET EARNINGS FOR YEAR, AS REPORTED		**$ 63,633**	$ 118,880	$ 18,312
ADJUSTMENTS				
ACCRETION OF ASSET RETIREMENT OBLIGATIONS	H	**–**	–	1,241
DEPRECIATION AND DEPLETION	H	**–**	–	542
SITE RESTORATION PROVISION	H	**–**	–	(1,072)
RELATED INCOME TAXES	H	**–**	–	(225)
ACCOUNTING FOR INCOME TAXES	D	**–**	(743)	(5,402)
RISK MANAGEMENT GAIN (LOSS), NET	F	**2,236**	(14,425)	8,659
NET EARNINGS BEFORE CHANGE IN ACCOUNTING PRINCIPLE - U.S. GAAP		**65,869**	103,712	22,055
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE, NET	H	**–**	(5,681)	–
NET EARNINGS – U.S. GAAP		**$ 65,869**	$ 98,031	$ 22,055

18. United States Accounting Principles and Reporting *(Continued)*

Consolidated Statements of Earnings – U.S. GAAP

FOR THE YEARS ENDED DECEMBER 31,	NOTE	**2004**	2003	2002
REVENUE, NET OF ROYALTIES		**$ 298,243**	$ 263,999	$ 179,100
EXPENSES				
OPERATING		**55,655**	49,916	45,546
TRANSPORTATION		**8,595**	8,447	8,167
GENERAL AND ADMINISTRATIVE		**15,215**	12,206	9,845
INTEREST AND FINANCE CHARGES		**33,733**	30,595	23,197
DEPLETION AND DEPRECIATION	H	**82,554**	61,749	54,931
FOREIGN EXCHANGE (GAIN) LOSS		**(14,631)**	(47,368)	1,583
ACCRETION OF ASSET RETIREMENT OBLIGATIONS	H	**1,670**	1,436	1,072
STOCK-BASED COMPENSATION		**3,410**	793	190
RISK MANAGEMENT LOSS (GAIN)	F	**5,165**	28,428	(13,083)
NET EARNINGS BEFORE TAXES AND NON-CONTROLLING INTEREST		**106,877**	117,797	47,652
INCOME TAX EXPENSE	F	**37,590**	14,195	25,597
NON-CONTROLLING INTEREST		**3,418**	(110)	–
NET EARNINGS BEFORE CHANGE IN ACCOUNTING PRINCIPLE – U.S. GAAP		**65,869**	103,712	22,055
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE, NET	H	**–**	(5,681)	–
NET EARNINGS – U.S. GAAP		**$ 65,869**	$ 98,031	$ 22,055
NET EARNINGS PER COMMON SHARE				
BEFORE CHANGE IN ACCOUNTING PRINCIPLE – U.S. GAAP				
BASIC		**$ 0.56**	$ 0.89	$ 0.19
DILUTED		**$ 0.53**	$ 0.85	$ 0.19
NET EARNINGS PER COMMON SHARE – U.S. GAAP				
BASIC		**$ 0.56**	$ 0.84	$ 0.19
DILUTED		**$ 0.53**	$ 0.80	$ 0.19

Statements of Other Comprehensive Income

FOR THE YEARS ENDED DECEMBER 31,	NOTE	**2004**	2003	2002
NET EARNINGS FOR THE YEAR – U.S. GAAP		**$ 65,869**	$ 98,031	$ 22,055
ACCOUNTING FOR HEDGING	F	**–**	858	(1,741)
COMPREHENSIVE INCOME	E	**$ 65,869**	$ 98,889	$ 20,314

18. United States Accounting Principles and Reporting *(Continued)*

Condensed Consolidated Balance Sheets

AS AT DECEMBER 31,	NOTE	2004		2003	
		AS REPORTED	**U.S. GAAP**	AS REPORTED	U.S. GAAP
ASSETS					
CASH	D	**$ 10,068**	**$ 10,068**	$ 15,548	$ 11,378
OTHER CURRENT ASSETS	D	**117,098**	**117,098**	94,937	99,107
PROPERTY AND EQUIPMENT		**1,178,550**	**1,178,550**	942,303	942,303
GOODWILL		**7,914**	**7,914**	–	–
DEFERRED FINANCING CHARGES AND OTHER	G	**9,729**	**6,944**	11,532	8,109
DEFERRED RISK MANAGEMENT LOSS	F	**7,252**	**–**	–	–
UNREALIZED LOSS ON GUARANTEE	I	**–**	**1,623**	–	–
		$ 1,330,611	**$ 1,322,197**	$ 1,064,320	$ 1,060,897
LIABILITIES AND SHAREHOLDERS' EQUITY					
CURRENT LIABILITIES		**$ 345,784**	**$ 345,784**	$ 253,142	$ 253,142
SENIOR TERM NOTES	G	**198,594**	**195,809**	213,246	209,823
ASSET RETIREMENT OBLIGATIONS		**18,006**	**18,006**	17,329	17,329
UNREALIZED HEDGE LIABILITY	F	**11,416**	**11,416**	–	10,895
GUARANTEE OBLIGATION	I	**–**	**1,623**	–	–
FUTURE INCOME TAXES	C, F, H	**261,196**	**258,357**	223,807	219,561
NON-CONTROLLING INTEREST		**71,537**	**71,537**	(110)	(110)
		906,533	**902,532**	707,414	710,640
CAPITAL STOCK	D	**135,526**	**165,513**	131,577	161,564
CONTRIBUTED SURPLUS		**3,840**	**3,840**	760	760
RETAINED EARNINGS		**284,712**	**250,312**	224,569	187,933
		424,078	**419,665**	356,906	350,257
		$ 1,330,611	**$ 1,322,197**	$ 1,064,320	$ 1,060,897

18. United States Accounting Principles and Reporting *(Continued)*

Condensed Consolidated Statements of Cash Flows

FOR THE YEARS ENDED DECEMBER 31,	**2004**	2003	2002
OPERATING ACTIVITIES			
NET EARNINGS	**$ 65,869**	$ 98,031	$ 22,055
AMORTIZATION OF DEFERRED CHARGES AND OTHER	**2,101**	2,208	1,367
DEPLETION AND DEPRECIATION	**82,554**	61,749	54,931
ACCRETION OF ASSET RETIREMENT OBLIGATIONS	**1,670**	7,117	1,072
UNREALIZED FOREIGN EXCHANGE (GAIN) LOSS	**(14,652)**	(47,388)	1,583
FUTURE INCOME TAXES	**34,839**	10,913	24,169
UNREALIZED RISK MANAGEMENT (GAIN) LOSS	**(1,464)**	24,296	(8,659)
OTHER	**6,214**	(2,033)	(446)
CHANGE IN NON-CASH WORKING CAPITAL	**20,742**	20,525	(16,702)
CASH FROM OPERATING ACTIVITIES	**197,873**	175,418	79,370
CASH FROM FINANCING ACTIVITIES	**111,179**	121,443	75,780
CASH USED IN INVESTING ACTIVITIES	**(310,362)**	(285,483)	(155,150)
CHANGE IN CASH	**(1,310)**	11,378	–
CASH, BEGINNING OF YEAR	**11,378**	–	–
CASH, END OF YEAR	**$ 10,068**	$ 11,378	$ –

Notes to the consolidated financial statements

DECEMBER 31, 2004 (Tabular amounts in thousands of Canadian dollars, unless otherwise stated)

A) *FULL COST ACCOUNTING*

The full cost method of accounting for crude oil and natural gas operations under Canadian and U.S. GAAP differ in the following respects. Under U.S. GAAP, an impairment test is applied to ensure the unamortized capitalized costs in each cost centre do not exceed the sum of the present value, discounted at 10%, of the estimated constant dollar, future net operating revenue from proved reserves plus unimpaired unproved property costs less applicable taxes. Under Canadian GAAP, a similar impairment test calculation is performed with the exception that cash flows from proved reserves are undiscounted and utilize escalated pricing to determine whether impairments exist. If an impairment exists, then the amount of the write down is determined using the fair value of reserves. The Company has completed a impairment test calculation at December 31, 2004 and for all prior years, with no write-downs required under either Canadian or U.S. GAAP.

B) *STOCK-BASED COMPENSATION*

Under Canadian GAAP, compensation costs have been recognized in the consolidated financial statements for stock options granted to employees and directors on or after January 1, 2003. For the effect on periods prior to 2003 of stock-based compensation on the Canadian GAAP financials, which would be the same adjustment under U.S. GAAP, see Note 11.

C) *FUTURE INCOME TAXES*

Under U.S. GAAP, enacted tax rates are used to calculate future taxes, whereas Canadian GAAP uses substantively enacted tax rates. The future income tax adjustments included in the reconciliation of net earnings under Canadian GAAP to U.S. GAAP and the balance sheet effects include the effect of such rate differences, if any, as well as the tax effect of the other reconciling items noted.

18. United States Accounting Principles and Reporting *(Continued)*

The net future income tax liability is comprised of:

AS AT DECEMBER 31,	2004	2003
FUTURE INCOME TAX LIABILITIES		
PROPERTY AND EQUIPMENT	**$ 199,931**	$ 169,855
TIMING OF PARTNERSHIP ITEMS	**67,089**	62,975
FOREIGN EXCHANGE GAIN ON LONG TERM DEBT	**10,169**	7,934
FUTURE INCOME TAX ASSETS		
ATTRIBUTED CANADIAN ROYALTY INCOME	**(9,015)**	(9,667)
ASSET RETIREMENT OBLIGATIONS	**(6,057)**	(6,024)
NON-CAPITAL LOSSES CARRIED FORWARD	**(53)**	(789)
OTHER	**(3,707)**	(4,723)
FUTURE INCOME TAXES	**$ 258,357**	$ 219,561

D) FLOW THROUGH SHARES

U.S. GAAP requires flow-through shares be recorded at their fair value without any adjustment for the renouncement of the tax deductions and any temporary difference resulting from the renouncement must be recognized in the determination of tax expense in the year incurred.

There were no flow-through shares issued in 2004. The impact of recording flow-through shares at their fair value for the year ended December 31, 2003, was to increase the future income tax provision by $0.7 million (2002 - $5.4 million) and to increase capital stock by a corresponding amount.

During 2003, the Company received $4.2 million in proceeds from the issuance of flow-through shares of which $4.2 million remained unspent as at December 31, 2003 (2002 - $17.6 million). Accordingly, under U.S. GAAP, these proceeds would be disclosed separately on the balance sheet as restricted cash and would not be treated as cash or cash equivalents for statement of cash flow reporting purposes. At December 31, 2002, the separate disclosure of restricted cash resulted in a negative ending cash balance which was reallocated to short term debt and reflected as a financing activity in the consolidated statements of cash flow.

E) COMPREHENSIVE INCOME

Statement of Financial Accounting Standards 130, "Comprehensive Income", requires the reporting of comprehensive income in addition to net earnings. Comprehensive income includes net income plus other comprehensive income. Management believes that it has no comprehensive income other than as described under Note 18F.

F) DERIVATIVE INSTRUMENTS AND HEDGING

On January 1, 2004, the Company implemented under Canadian GAAP, EIC 128 which requires derivatives not designated as hedges to be recorded on the balance sheet as either assets or liabilities at their fair value. Changes in the derivative's fair value are recognized in current period earnings. Under the transitional rules, any gain or loss at the implementation date is deferred and recognized into revenue once realized. At January 1, 2004 a deferred loss was recognized in the amount of $10.9 million. During the year, $3.6 million of the deferred loss was charged to earnings. The remaining balance of $7.3 million relates to the interest rate swap and will be recognized in annual amounts of $1.6 million until eliminated in 2009. Currently, the Company has not designated any of its financial instruments as hedges for accounting purposes.

For U.S. GAAP, the Company adopted Statement of Financial Accounting Standards ("SFAS") 133 effective January 1, 2001. SFAS 133 requires all derivatives to be recorded on the balance sheet as either assets or liabilities at their fair value. Changes in the derivative's fair value are recognized in current period earnings unless specific hedge accounting criteria are met. To eliminate future GAAP reconciling items the Company has not designated any of its financial instruments, for year ended December 31, 2004, as hedges for U.S. GAAP purposes under SFAS 133.

18. United States Accounting Principles and Reporting *(Continued)*

The deferred loss, recognized at January 1, 2004 under the Canadian GAAP transitional provision of EIC 128, has already been recognized in earnings for U.S. GAAP and becomes a reconciling item at December 31, 2004.

Prior to January 1, 2004, the natural gas and crude oil futures contracts were accounted for as cash flow hedges. These contracts were recorded at fair value on the balance sheet as a $2.0 million liability at December 31, 2003. The effective portion of the change in fair value is recorded in comprehensive income, net of tax. The ineffective portion of the change in fair value was recorded in net earnings, net of tax. The effective portion of these commodity contracts was a $0.9 million gain, which is recorded in comprehensive income as at December 31, 2003 (2002 - $1.7 million loss). The ineffective portion of these commodity contracts is $nil which is recorded in net earnings as at December 31, 2003 (2002 - $253 thousand loss).

During 2003, it was determined that the interest rate swap arrangements relating to the Company's senior term notes, Note 7, do not qualify for hedge accounting in accordance with SFAS 133 and should be accounted for on a mark-to-market basis. Accordingly, 2002 comparative amounts have been restated to reflect the appropriate accounting treatment. As a result, the change in the fair value of the interest rate swap arrangements of $15.4 million, previously recorded as an increase to the senior term notes, was charged to earnings, net of the future income taxes of $6.5 million, with a corresponding increase in net earnings and retained earnings of $8.9 million. Basic earnings per share and diluted earnings per share for the year ended December 31, 2002, increased $0.07 and $0.08 per share respectively, as a result of the restatement.

G) *DEFERRED FINANCING CHARGES*

Under U.S. GAAP, discounts on long-term debt are classified as a reduction of long-term debt rather than as deferred financing charges. At December 31, 2004 deferred financing charges and senior term notes were reduced by $2.8 million (2003 - $3.4 million).

H) *ASSET RETIREMENT OBLIGATIONS*

In 2003, the Company early adopted the Canadian Accounting Standard for asset retirement obligations, as outlined in the CICA handbook, section 3110. This standard is equivalent to U.S. SFAS 143, "Accounting for Asset Retirement Obligations", which was effective for fiscal periods beginning on or after January 1, 2003. Early adopting the Canadian standard eliminated a U.S. GAAP reconciling item in respect to accounting for the obligations. However, a difference is created in how the transition amounts are disclosed. U.S. GAAP requires the cumulative impact of a change in an accounting principle be presented in the current year consolidated statement of earnings and prior periods not be restated. Consequently, prior year comparative periods, under U.S. GAAP, have been revised to eliminate the prior period restatement made under Canadian GAAP.

I) *GUARANTEE*

As discussed in Note 4 to the consolidated financial statements, Mazeppa Processing Partnership ("MPP") has guaranteed payment of certain obligations of its limited partner under a credit agreement between the limited partner and a syndicate of lenders. Canadian GAAP requires disclosure only, of this type of financial arrangement. U.S. GAAP under FIN 45 "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others", requires the fair valuation of the guarantee and the inclusion of the liability in the consolidated balance sheets.

J) *STATEMENTS OF CASH FLOW*

The consolidated statements of cash flow include under investing activities, changes in working capital for items not affecting cash, such as accounts payable and accounts receivable, related to the non-cash elements of property and equipment additions. This presentation is not permitted under U.S. GAAP. The amount at December 31, 2004 of $29.2 million (2003 - $8.7 million, 2002 – $1.0 million) has been reallocated to the change in non-cash operating working capital for U.S. GAAP presentation purposes.

18. United States Accounting Principles and Reporting *(Continued)*

K) RECEIVABLE AND PAYABLE AMOUNTS

AS AT DECEMBER 31,	**2004**	2003
(IN THOUSANDS OF CANADIAN DOLLARS)		
ACCOUNTS RECEIVABLE AND OTHER INCLUDES THE FOLLOWING:		
REVENUE RECEIVABLE	**$ 72,510**	$ 63,687
JOINT INTEREST RECEIVABLE	**32,077**	21,685
OTHER RECEIVABLES	**12,511**	13,735
	$ 117,098	$ 99,107

AS AT DECEMBER 31,	**2004**	2003
(IN THOUSANDS OF CANADIAN DOLLARS)		
ACCOUNTS PAYABLE AND ACCRUED LIABILITIES INCLUDES THE FOLLOWING:		
TRADE PAYABLES	**$ 97,608**	$ 67,753
ROYALTIES PAYABLE	**18,488**	10,920
OTHER PAYABLES	**9,387**	7,212
	$ 125,483	$ 85,885

L) RECENT ACCOUNTING PRONOUNCEMENTS

During 2004, the following new standards were issued:

Exchange of non-monetary assets

In December 2004, the FASB issued Statement of Financial Accounting Standards No. 153 "Exchanges of Non-monetary Assets – an amendment of APB Opinion No. 29". This Statement amends APB Opinion 29 to eliminate the exception for non-monetary exchanges of similar productive assets and replaces it with a general exception for exchanges of non-monetary assets that do not have commercial substance. A non-monetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. The adoption of this Standard is not expected to have any material impact on the Company's financial position or results of operations.

Share-based payment

Also in December 2004, the FASB issued revised SFAS No. 123 (revised 2004) "Share-Based Payment". This Statement requires that the cost resulting from all share-based transactions be recorded in the financial statements. The Statement establishes fair value as the measurement objective in accounting for share-based payment arrangements and requires all entities to apply a fair-value-based measurement in accounting for share-based payment transactions with employees. The Statement also establishes fair value as the measurement objective for transactions in which an entity acquires goods or services from non-employees in share-based payment transactions. The Statement replaces FASB Statement No. 123 "Accounting for Stock-Based Compensation" and supersedes APB Opinion No. 25 "Accounting for Stock Issued to Employees". The provisions of this Statement will be effective for the Company beginning with its fiscal year ending 2006. The Company is currently evaluating the impact this new Standard will have on its operations, but believes that it will not have a material impact on the Company's financial position or results of operations.

Supplemental Oil and Natural Gas Information (unaudited)

A) Net Proved Oil and Natural Gas Reserves

The net proved oil and natural gas reserve estimates as at December 31, 2004, 2003 and 2002 set forth below were prepared in accordance with guidelines established by the Securities and Exchange Commission and accordingly were based on existing economic and operating conditions. Oil and natural gas prices in effect as of the respective year ends were used without any escalation except in those instances where the sale is covered by contract, in which case the applicable contract price is used. Operating costs, royalties and future development costs were based on current costs with no escalation.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production and timing of development expenditures. The following reserve data represents estimates only and should not be construed as being exact. Moreover, the present value should not be construed as the current market value of the Company's oil and natural gas reserves or the costs that would be incurred to obtain equivalent reserves. All of the reserves are located in Canada.

ESTIMATED QUANTITIES OF RESERVES

	2004		2003		2002	
YEARS ENDED DECEMBER 31,	**CRUDE OIL & NGL'S (MBBLS)**	**NATURAL GAS (MMCF)**	CRUDE OIL & NGL'S (MBBLS)	NATURAL GAS (MMCF)	CRUDE OIL & NGL'S (MBBLS)	NATURAL GAS (MMCF)
BALANCE, BEGINNING OF YEAR	**14,542**	**326,573**	10,723	314,501	9,777	262,448
REVISIONS OF PREVIOUS ESTIMATES	**2,797**	**16,547**	2,297	(12,821)	529	11,712
EXTENSIONS, DISCOVERIES AND OTHER ADDITIONS	**3,026**	**47,713**	2,869	54,128	1,829	58,853
ACQUISITIONS OF MINERALS IN PLACE	**427**	**9,444**	404	2,333	514	18,805
DISPOSITIONS OF MINERALS IN PLACE	**(440)**	**(3,160)**	–	–	(84)	(5,343)
PRODUCTION	**(1,581)**	**(37,142)**	(1,751)	(31,568)	(1,842)	(31,974)
BALANCE, END OF YEAR	**18,771**	**359,975**	14,542	326,573	10,723	314,501
PROVED DEVELOPED RESERVES						
BALANCE, BEGINNING OF YEAR	**10,309**	**288,899**	9,723	293,836	8,938	232,319
BALANCE, END OF YEAR	**14,265**	**292,306**	10,309	288,899	9,723	293,836

B) Capitalized costs related to oil and natural gas activities

The aggregate capitalized costs of oil and natural gas activities and costs incurred in oil and natural gas property acquisitions, development and exploration activities are as follows (excluding MPP and parts inventory):

CAPITALIZED COSTS

AS AT DECEMBER 31, (in thousands of Canadian dollars)	**2004**	2003
PROVED PROPERTIES	**$1,218,826**	$ 939,598
UNPROVED PROPERTIES:		
ACQUISITION	**117,194**	103,977
EXPLORATION	**83,238**	69,820
ACCUMULATED DEPLETION AND DEPRECIATION	**(318,583)**	(238,413)
	$1,100,675	$ 874,982

Supplemental Oil and Natural Gas Information (unaudited) *(Continued)*

COSTS INCURRED ON UNPROVED PROPERTIES

		INCLUDES COSTS INCURRED IN			
AS AT DECEMBER 31 (in thousands of Canadian dollars)	**CUMM. 2004**	2004	2003	2002	PRIOR YEARS
ACQUISITION	**$ 117,194**	$ 13,217	$ 2,933	$ (9,720)	$ 110,764
EXPLORATION	**83,238**	13,418	15,615	4,000	50,205
	$ 200,432	$ 26,635	$ 18,548	$ (5,720)	$ 160,969

COSTS INCURRED

YEARS ENDED DECEMBER 31, (in thousands of Canadian dollars)	**2004**	2003	2002
ACQUISITION COSTS (NET OF DISPOSITION)			
PROVED PROPERTIES	**$ 12,686**	$ 11,224	$ 27,157
UNPROVED PROPERTIES	**13,217**	2,933	(9,720)
DEVELOPMENT COSTS			
DEVELOPMENT OF PROVED UNDEVELOPED RESERVES	**60,227**	25,232	21,280
OTHER	**136,198**	115,612	52,971
EXPLORATION COSTS	**76,648**	64,615	63,462
TOTAL COSTS INCURRED	**$ 298,976**	$ 219,616	$ 155,150

Costs are transferred into the depletion base on an ongoing basis as the undeveloped properties are evaluated and proved reserves are established or impairment determined. Pending determination of proved reserves attributable to the above costs, the Company cannot assess the future impact on the amortization rate.

C) Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Natural Gas Reserves

The standardized measure of discounted future net cash flows and changes therein relating to proved oil and natural gas reserves ("Standardized Measure") does not purport to present the fair market value of the Company's oil and natural gas properties. An estimate of such value should consider, among other factors, anticipated future prices of oil and natural gas, the probability of recoveries in excess of existing proved reserves and acreage prospects, and perhaps different discount rates. It should be noted that estimates of reserve quantities, especially from new discoveries, are inherently imprecise and subject to substantial revisions. The computation also excludes values attributable to the Company's midstream interests, referred to in the Financial Statements as MPP.

Supplemental Oil and Natural Gas Information (unaudited) *(Continued)*

Under the Standardized Measure, future cash inflows were estimated by applying year end prices, adjusted for contracts currently in place to deliver production to the estimated future production of year end proved reserves. Future cash inflows were reduced by estimated future production and development costs based on year end costs to determine pre-tax cash inflows. Future taxes were computed by applying the statutory tax rate to the excess of pre-tax cash inflows over the Company's tax basis in the associated proved oil and natural gas properties. Tax credits and net operating loss carry forwards were also considered in the future income tax calculation. Future net cash inflows after income taxes were discounted using a 10 percent annual discount rate to arrive at the Standardized Measure.

YEARS ENDED DECEMBER 31, (in thousands of Canadian dollars)	**2004**	2003	2002
FUTURE CASH INFLOWS	**$3,160,270**	$ 2,467,604	$ 2,460,747
FUTURE PRODUCTION COSTS	**(971,392)**	(785,187)	(507,576)
FUTURE DEVELOPMENT COSTS	**(102,557)**	(76,708)	(56,209)
FUTURE NET CASH FLOWS	**2,086,321**	1,605,709	1,896,962
INCOME TAXES	**(539,539)**	(460,291)	(733,434)
TOTAL UNDISCOUNTED FUTURE NET CASH FLOWS	**1,546,782**	1,145,418	1,163,528
10 PERCENT ANNUAL DISCOUNT FOR ESTIMATED TIMING OF CASH INFLOWS	**(793,904)**	(592,409)	(509,831)
STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS	**$ 752,878**	$ 553,009	$ 653,697

(1) The Company estimates that it will incur $31.4 million in 2005, $24.1 million in 2006 and $5.6 million in 2007 to develop proved undeveloped reserves.

The following table sets forth an analysis of changes in the standardized measure of discounted future net cash flows from proved oil and natural gas reserves:

YEARS ENDED DECEMBER 31, (in thousands of Canadian dollars)	**2004**	2003	2002
BEGINNING OF YEAR	**$ 553,009**	$ 653,697	$ 317,461
SALES OF PRODUCTION, NET OF PRODUCTION COSTS	**(226,408)**	(197,323)	(126,745)
NET CHANGE IN SALES PRICES, NET OF PRODUCTION COSTS	**42,728**	(64,509)	502,652
EXTENSIONS, DISCOVERIES AND ADDITIONS	**161,106**	144,565	198,811
CHANGES IN ESTIMATED FUTURE DEVELOPMENT COSTS	**(54,838)**	(39,965)	(58,187)
DEVELOPMENT COSTS INCURRED DURING THE PERIOD WHICH REDUCED FUTURE DEVELOPMENT COSTS	**184,053**	85,586	66,881
REVISIONS IN QUANTITY ESTIMATES	**306,271**	(69,386)	70,721
ACCRETION OF DISCOUNT	**75,908**	101,612	42,348
PURCHASE OF RESERVES	**(7,749)**	6,328	55,129
SALES OF RESERVES	**4,416**	–	(20,051)
NET CHANGE IN INCOME TAX	**(42,270)**	156,350	(234,813)
CHANGES IN PRODUCTION RATES (TIMING) AND OTHER	**(243,348)**	(223,946)	(160,510)
STANDARDIZED MEASURE, END OF YEAR	**$ 752,878**	$ 553,009	$ 653,697

Head Office

Compton Petroleum Corporation
Fifth Avenue Place, East Tower
Suite 3300, 425-1st Street S.W.
Calgary, Alberta, Canada T2P 3L8
Telephone: (403) 237-9400
Fax: (403) 237-9410

Email: investorinfo@comptonpetroleum.com
Website: http://www.comptonpetroleum.com

Directors

M.F. Belich, Q.C. [1]
Chairman & President,
Enbridge International Inc.,
Chairman, Compton Petroleum Corporation

I.J. Koop, P.Eng. [2]
Chairman & C.E.O., IKO Resources Inc.

J.W. Preston
Account Executive, Sun Microsystems

J.T. Smith, P.Geol. [3]
Independent Retired Petroleum Executive

J. A. Thomson, C.A. [4]
Independent Businessman

E.G. Sapieha, C.A.
President & C.E.O.,
Compton Petroleum Corporation

1 *Chairman, Corporate Governance Committee*
2 *Chairman, Human Resources, Compensation, Environmental, Health and Safety Committee*
3 *Chairman, Engineering, Reserves and Operations Committee*
4 *Chairman, Audit, Finance and Risk Committee*

Executive

E.G. Sapieha, C.A.
President & C.E.O.

M.J. Stodalka, P.Eng.
VP Operations & Engineering

M.R. Junghans, P.Geol.
VP Exploration

K.N. Davies, P.Geoph.
VP New Ventures

D.C. Longfield, P.Eng.
VP Special Projects

N.G. Knecht, C.A.
VP Finance & C.F.O.

T.G. Millar, LL.B.
VP, General Counsel & Corporate Secretary

Consulting Engineers

Netherland Sewell & Associates, Inc.

Bankers

Bank of Montreal
The Bank of Nova Scotia
The Toronto-Dominion Bank

Legal Counsel

Fraser Milner Casgrain LLP

Auditors

Grant Thornton LLP

Transfer Agent and Registrar

Computershare Trust Company
of Canada

Stock Exchange Listing

The Toronto Stock Exchange
Trading symbol: CMT

Panoramic landscape images courtesy of Compton Geologist, D. Proctor.

COMPTON
PETROLEUM CORPORATION

Compton Petroleum Corporation

Fifth Avenue Place, East Tower

Suite 3300, 425-1st Street S.W.

Calgary, Alberta, Canada T2P 3L8

Telephone: (403) 237-9400 — Fax: (403) 237-9410

Email: investorinfo@comptonpetroleum.com — Website: http://www.comptonpetroleum.com